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# An engineering study of the driftwood-benezette gas field in Pennsylvania.

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# AN ENGINEERING STUDY OF THE DRIFTWOOD-BENEZETTE GAS FIELD IN PENNSYLVANIA

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## An Engineering Study of the

# Driftwood - Benezette Gas Fields In Elk, Cameron, and Clearfield Counties of Penna.

**By Commander C. B. Connally* and P. F. Fulton****

### I. Introduction

This paper presents a petroleum engineering approach to the evaluation of production practices employed in the Driftwood-Benezette gas field in Pennsylvania, and compares the results of such practices with those which might have been accomplished had the field been developed and operated in the most efficient manner, or in accordance with modern petroleum conservation laws.

The Driftwood-Benezette gas field is important to this study only in that it provides a means for illustrating production practices generally employed in all Pennsylvania gas fields. Therefore, no attempt has been made to set forth details of engineering and geologic interest not closely related to production practices.

Petroleum production practices in Pennsylvania have remained the same in principle since the discovery of the Drake well in 1859. There are no laws restricting petroleum production even though it is a well known fact that "wide-open" flow may cause great underground losses of oil or gas; moreover, there are no laws protecting landowners' correlative rights—the right to enjoy the use of one's property so long as this enjoyment does not do injury to others.[1]

There have been several proposals[2] for petroleum conservation laws which would require or encourage the development and operation of a petroleum reservoir as a single unit rather than on the wasteful and costly basis of "every man for himself." None has been enacted, however, and it appears that Pennsylvania may become the leading oil and gas producing state where no such laws are in effect. It is indeed a mystery why no such laws have been enacted. One would think that Pennsylvania, the founding state of the petroleum industry, would have been a leader in petroleum regulatory law. There must be some merit to petroleum conservation and unitization laws, for no state has ever repealed such a law. The Interstate Oil Compact Commission, which through engineering, research, and other committees functions to advise the various states on petroleum regulatory measures, has recommended the enactment of a unitization law.[3] Does it not seem logical that there should be a minimum waste of petroleum resources, and that a landowner should be permitted to recover his fair share of the oil or gas underlying his land, and only his fair share, without the drilling of unnecessary wells?

Perhaps many Pennsylvanians are not acutely aware of the waste of their petroleum resources or the infringement on their correlative rights caused by maximum-rate production practices employed in Pennsylvania. This study has been made in an attempt to illustrate, quantitatively, the effects of such practices as they relate to natural-gas production.

The Driftwood-Benezette field provides a good example for illustrating natural-gas production practices in Pennsylvania. This field was intensely drilled soon after its discovery and allowed to produce at maximum rate. Each landowner had to get his gas to the surface before his neighbor drained it away. It is the authors' opinion that this caused the drilling of about 200 more wells than would have been necessary to produce the field efficiently, and that open-flow production will cause the underground loss of at least 20 billion cubic feet of gas, with a net value of approximately $2,000,000.

Unfortunately, accurate results cannot be obtained from the data available. Throughout this study, however, the authors continually strove to favor the use of results and assumptions which would not exaggerate the adverse effects of existing production practices.

### II. Inadequacy of Engineering Data

It became apparent at the beginning of this study that the lack of petroleum regulatory laws has resulted in an inadequacy of engineering data.

It is impossible for engineers to make accurate engineering studies, upon which plans for future gas production, transportation, storage and marketing must be based, without complete and accurate engineering information. Furthermore, this information must be readily available, at a central source, to all interested parties.

In 1935 the Bureau of Mines introduced a method for computing gas-well capacities and for applying this information to production practices.[4] The basic equation[5] set forth in that report is used throughout the natural gas producing industry—even in Pennsylvania—yet the data available on Pennsylvania wells for use in that equation are entirely inadequate for accurate calculations.

Though there are no laws preventing operators from obtaining these data on their own wells, few will voluntarily close in a well or restrict its production while their neighbor drains gas from under their land at a maximum rate. Further, in order to provide maximum benefit, this information must be standardized and compiled under a well organized program, enforced by a central authority and maintained readily available at a central source.

This lack of adequate information has obviously lead to inaccuracies in much of the data that have been obtained. Probably the greatest inaccuracies have been in measuring the shut-in pressures of the wells, the very heart of the information used in petroleum engineering studies.

Another source of difficulty to an engineer is the confidential nature of production information on privately owned wells. An accurate evaluation of a well's performance requires the comparison of that well with other wells in the near vicinity, and an evaluation of the reservoir as a whole may require the use of performance data on any well in the reservoir.

Specific examples of either inadequate or inaccurate information encountered during the course of this study are listed as follows:

1. Shut-in well pressures are often inaccurate. Most wells were shut in for less than 24 hours when their pressures were recorded, some for only an hour or less.

2. The entire reservoir has never been shut in and the average pressure recorded, nor are individual wells shut in periodically for this purpose. One accurate reservoir pressure, after sufficient gas had been produced to show a pressure decline, would have been sufficient to compute total gas reserves. As the situation stands, operators are merely guessing at gas reserves, and no one will ever know how much gas is lost due to production practices.

3. Production information on privately owned land is confidential and, there-

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best advantage its resources of men and materials.

### Acknowledgement

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## Wrather Retires As Director Of U. S. Geological Survey

**Dr. William Embry Wrather,** who recently retired as Director of the Geological Survey "has guided Survey Activities through 12 years of growth in service to the Nation during the difficult years of war and the later period of adjustment to an expanding economy," according to Secretary of the Interior Douglas McKay. Dr. Wrather was appointed in 1943, at a time when heavy demands were being made on the Survey for emergency services to the Nation in the midst of a world war.

Born in Kentucky and a graduate of the University of Chicago in geology and law, Dr. Wrather brought to the Survey a unique combination of administrative abilities gained through years of experience in the petroleum industry.

In 1954 he was given the 50th John Fritz Medal, and cited as "a geologist of worldwide experience and fame; an outstanding scientist and historian; a wise leader distinguished for his service to the Nation."

Under Dr. Wrather's leadership much progress was made in various facets of the science of hydrology and in the accumulation of basic water facts.

A rapidly expanding program of water resources investigations has been guided toward broad objectives in appraising the Nation's water resources, developing a better understanding of the principles governing the occurrence and movements of water, and in determining current water use and water requirements.

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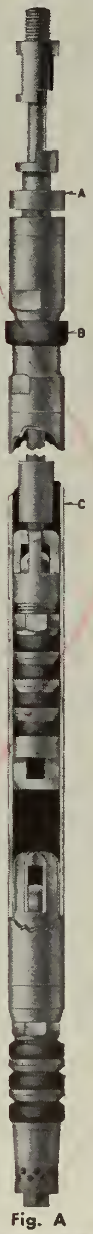

Fig. A

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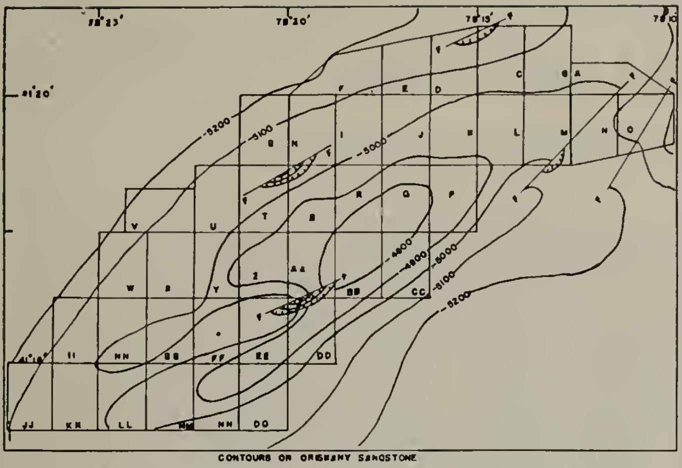

Figure 1—Structure Map, Driftwood-Benezette Gas Field

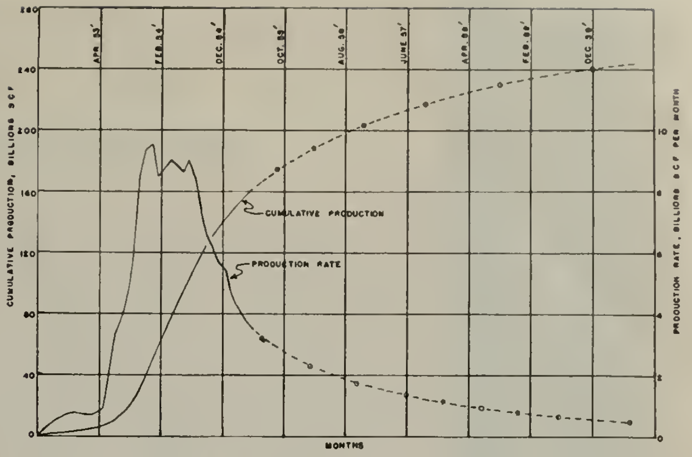

Figure 3—Cumulative Production and Production Rate vs. Time

fore, not available to the public or to all interested producing companies.

4. No records could be found showing shut-in pressures for wells on more than one occasion after having been cut in to the pipeline. This information is necessary in order to determine a well's performance characteristics and behavior as described in Section V, A and B.

5. No one producer or regulatory body has all the data on all the wells in the reservoir. Absence of monthly production rates for all wells is the most important example of this inadequacy. Other missing information might be as follows: The drilling method used, whether or not a well was shot, original well-head pressures and shut-in time, and whether or not a well had been abandoned.

6. The reservoir temperature has never been measured.

7. Very few reservoir sand thicknesses have been recorded.

8. Well locations are not recorded in a standard form.

9. Neither the porosity nor the permeability of the sand has ever been measured.

In view of the above, the results brought out in this study are not nearly so accurate nor significant as they otherwise might have been. Perhaps the inadequacy of this study will serve to indicate the necessity for such state statutes as will provide for the compilation of information necessary to conduct accurate engineering studies.

## III. History of Operations

### A. The Reservoir

The Driftwood-Benezette gas field is the largest known gas field in Pennsylvania, covering about 42,000 acres in Elk, Cameron, and Clearfield Counties. Production is from the highly faulted Oriskany sandstone, which in this area is mostly "medium-grained, light gray, quartzose, slightly calcareous."[6] The Oriskany is capped by the Onondaga limestone formation.

Figure 1 shows the approximate area of the reservoir superimposed on a contour map on the Oriskany sandstone as constructed by Fettke.[7] Figure 2 shows locations of all wells numbered in the sequence in which they were completed or drilling operations abandoned, although numbers for dry holes have been omitted on the drawing.

It should not be construed that the reservoir has such a jagged boundary as is indicated by the block areas in Figures 1 and 2. These blocks established by the authors were used to compute the average reservoir pressure as described in Section IV.

This field is located on the Driftwood anticline, the highest point on which is the Driftwood dome, located about one mile northeast of the town of Driftwood. This dome is not shown in Figure 1

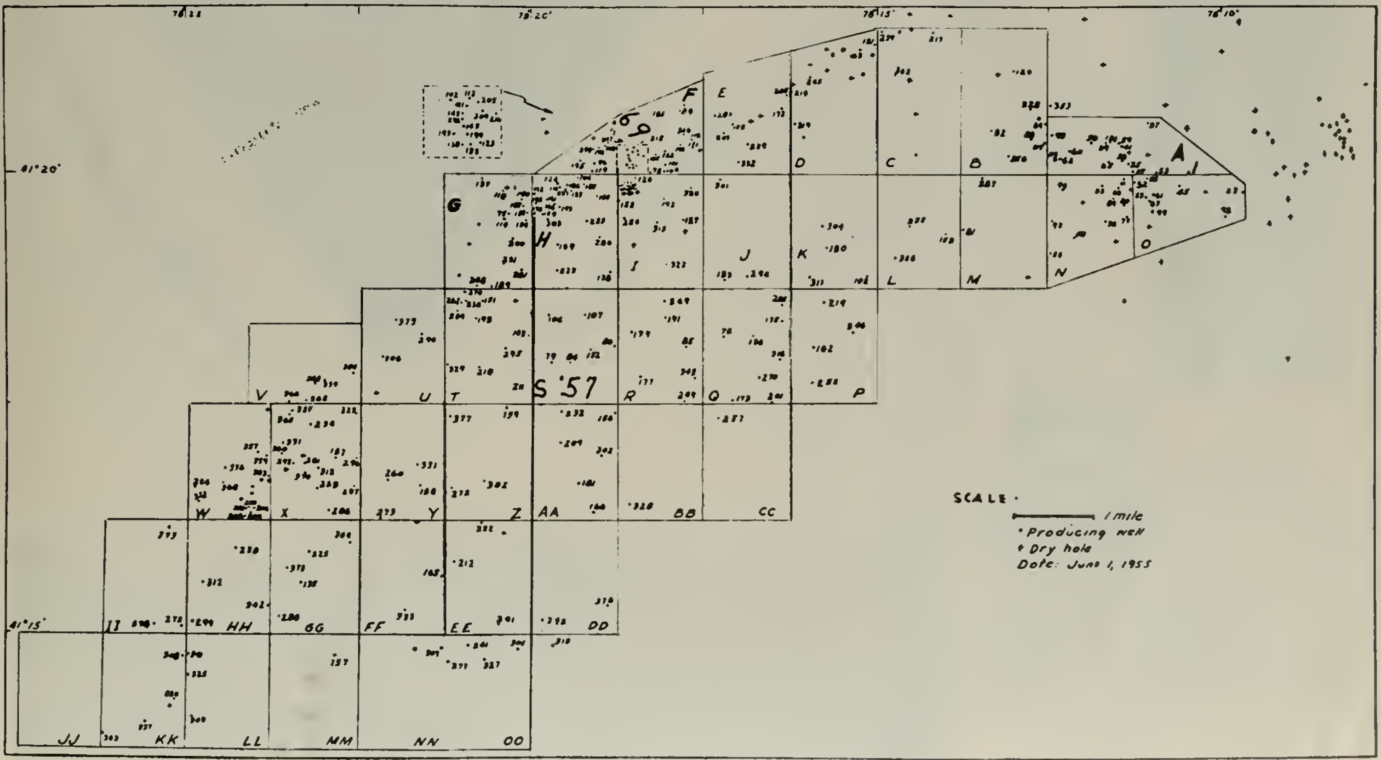

Figure 2—Block area map, Driftwood-Benezette Gas Field

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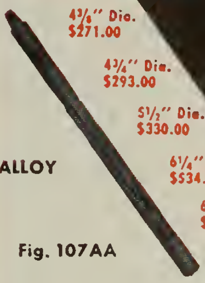

Fig. 107AA

3¼" Dia. $244.00
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4¾" Dia. $293.00
5½" Dia. $330.00
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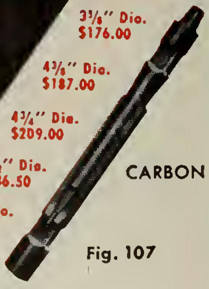

Fig. 107

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since the dome itself proved to be outside the productive boundary of the reservoir, as indicated by the numerous dry holes shown just to the northeast of the reservoir in Figure 2.

The northeast or Driftwood end of this reservoir was discovered first. The discovery well was Sylvania's S. C. Eaton No. 1 (Figure 2, well 1-A) completed September 15, 1951. Since this well was situated relatively low on the southwest plunge of the Driftwood dome, subsequent tests were made high on the dome in and around the town of Driftwood, none of which proved productive apparently because of a tight sand stratigraphic closure at the northeast end of the reservoir. Development was then shifted down the plunge to the southwest.

The Keta Oil and Gas Company's Charleroi Mountain Club No. 1 (Figure 2, well 57-S) on the Benezette dome opened the Benezette end of the reservoir in December, 1952. Then in March, 1953, the Benezette Valley Development Company brought in the William Woodring No. 1 (Figure 2, well 69-F). This well was extremely important in that it is some 300 feet lower on the flanks of the Benezette dome than the Charleroi well, indicating that the Driftwood-Benezette field was much larger than had previously been estimated.[8] This led to the furious drilling race between private landowners which resulted in the dense well pattern as shown in Figure 2, areas F, G and H. Presumably, if the areas to the south had not been mostly state-owned land, the entire field would have been drilled into a similar pattern.

### B. Drilling and Production Practices

#### 1. Drilling and Gauging

Drilling operations reached a peak in August, 1953, when 22 producing wells were brought in. The rate then dropped slightly and leveled off at about fifteen to twenty wells per month until July, 1954, at which time there began a rapid decline in the drilling rate.

Most of the early drilling was with cable tools which averaged about sixty feet per day. Rotary drilling was later used, which averaged about 180 feet per day; however, lost circulation and completion problems were frequently caused by the high density (17 pounds per gallon) drilling mud. Completion problems were often overcome by drilling-in with cable tools, but a more recent practice of using air-rotary drilling with gas completions has been highly successful in eliminating both of these difficulties. The air-rotary has shown a penetration rate of about twice that of the regular rotary.[9]

All methods employ the practice of setting a seven-inch O. D. casing about ten feet into the Onondaga limestone, and then drilling a 6⅛-inch hole into or through the Oriskany sandstone.

Open-flow capacities of wells are measured with pitot tubes while the gas is discharged to the atmosphere. Shut-in pressures are generally recorded after wells have been closed in for 24 hours, although the rush to cut the wells into the pipeline frequently permits only a few hours shut-in time.

#### 2. Production Practices

Little can be said of production practices except that wells are cut in to the pipeline as quickly as possible and permitted to flow at maximum rate. Figure 3 shows the cumulative production and production rate of the field plotted against time. The dotted portion of the curves represents the predicted recovery and recovery rates as explained in detail in Section V, C.

There has been no evidence of water drive during production from this field. There have been occasions of wells being drowned out by water, but this difficulty has frequently been relieved, at least temporarily or partially, by shutting in the wells for a few days.

### IV. Determination of Reserves

An accurate determination of gas reserves in a reservoir can be made only when accurate reservoir pressures are known. Since the Driftwood-Benezette reservoir has never been shut in in order to determine a reservoir pressure, and since pressures for individual wells are not periodically recorded, any method used in computing reserves is largely guesswork. The original pressure was most probably about 4,020 pounds per

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FIGURE 6. AVERAGE WELL FLOW RATE DECLINE

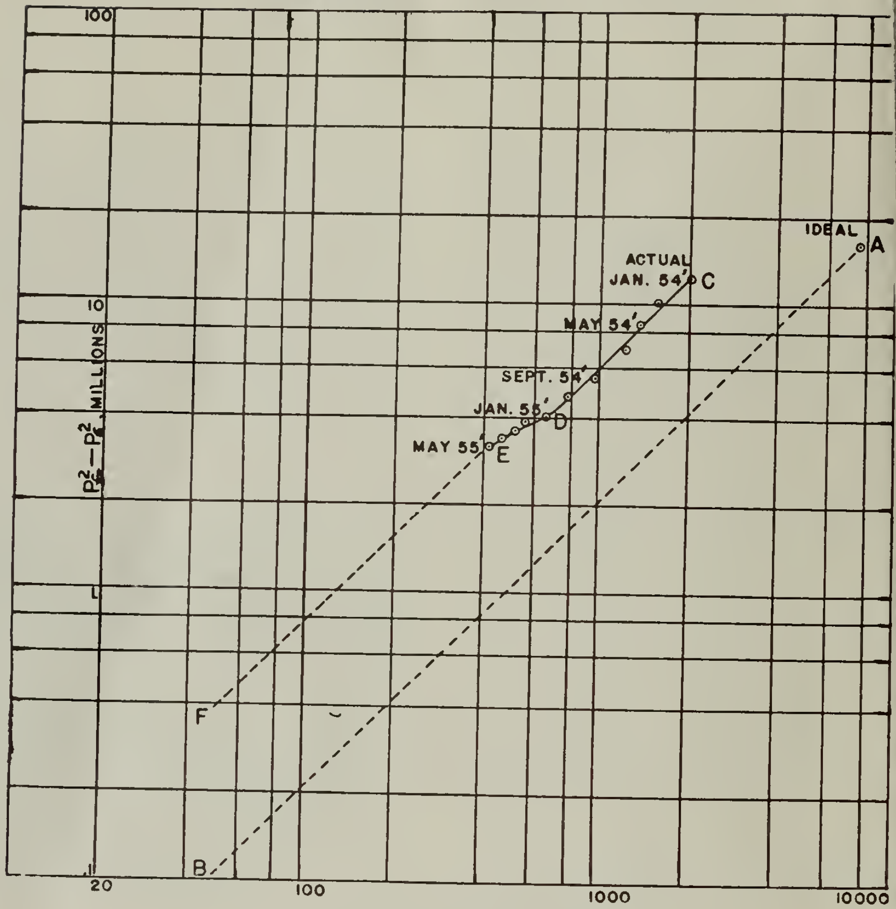

Figure 6—Average Well Flow Rate Decline

square inch gage, as measured at the well head. Obviously, no other pressure would be needed to compute reserves if the boundaries of the reservoir, the porosity, the per cent water saturation, and the sand thickness were known. However, in view of the highly faulted structure of this reservoir, the probable wide variation in porosity, and the doubtful boundaries as estimated, the only practicable method for determining reserves is by the use of declining reservoir pressures with cumulative production, as is shown graphically by Figure 4, and as explained in detail later in this section.

The only course for determining the average reservoir pressure lay in averaging pressures by areas, area pressures being obtainable from original pressures for new wells. It is believed that the boundaries of the reservoir are sufficiently well established so that it can be divided into areas as shown in Figure 2, and that each area has roughly the same average porosity and sand thickness. Though this may not be entirely true, the method of averaging area pressures in order to determine the over-all reservoir pressure is not overly demanding of an accurate reservoir area, and it is not necessary that the sand thickness or porosity be known, provided each area is assumed to have equal pore space. The reservoir area as shown is comprised of forty-one approximately equal-sized blocks of about one thousand acres each.

The only difficulty lay in determining the average area pressures at a selected date or dates. The pressure recorded for a well drilled in the area on or near the selected date could not be used with any degree of accuracy, for often the well would be in such close proximity to another that its pressure would be greatly affected, or the pressure shown for a well drilled at a later date in the same vicinity might have been considerably higher. Many additional factors had to be considered, such as the location of the wells in the area, their distance apart, the length of shut-in time compared to flow rate, and pressures in adjoining areas.

It soon became apparent that many recorded well pressures were lower than they should have been. Most of the wells were shut in for less than twenty-four hours when their pressures were recorded. This is far short of the time estimated to have been necessary for the pressure to stabilize in sand of such low permeability. It has been illustrated that pressures recorded after three days may still be well below the stabilized pressures.[10]

It was impossible to select any single date near which, during the early and late stages of development, wells were drilled in a majority of the areas. This required such an extensive use of estimated area pressures that little reliability could be placed in the computed average. It was, therefore, decided to determine the one most accurate average reservoir pressure which occurred well along in the productive life of the reservoir. Only one pressure, other than the original, is needed to compute reserves, and one good pressure is considered to be more accurate than a decline curve average of several poor ones. In order to determine the most accurate pressure each block area was considered separately. Again, weighing all significant

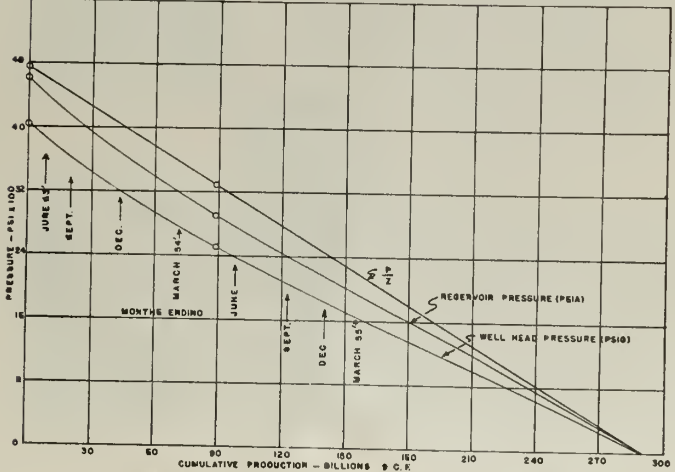

Figure 4—Pressure Decline with Cumulative Production

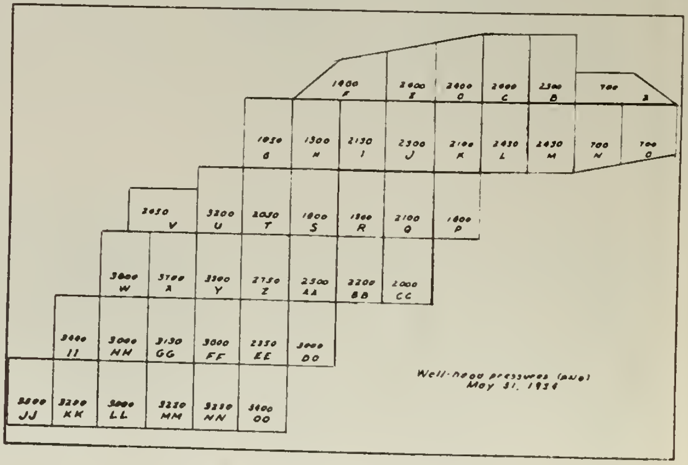

Figure 5—Pressures by Block Areas

factors stated above, every instance in which a well pressure or several well pressures appeared to reasonably represent that for the block area was recorded under the date shown. When such pressures for all areas had been recorded, the widest coverage of area pressures fell near the date of May 31, 1954. That date was, therefore, selected for determining the over-all average reservoir pressure. In cases where a block area failed to show a pressure on or near that date, it was possible to interpolate between dates on either side of May, 1954, or to estimate the area pressure from those shown for surrounding areas. Well-head pressures thus determined are shown in Figure 5. The average of these gage pressures came to 2,490 pounds per square inch.

The pressure due to the weight of the column of gas was computed using the equation

$$Pw = \frac{P_x ZRT\ 144}{MH} - .5Px^*$$

where

$Pw$ = well-head pressure in pounds per square inch absolute.
$P_x$ = pressure due to the weight of the gas column in pounds per square inch,
$Z$ = gas compressibility factor at average temperature in the well bore and at well-head pressure,
$R$ = gas constant,
$T$ = average temperature of the gas column,
$M$ = molecular weight of the gas,
$H$ = average depth of the reservoir below the surface.

If natural gas expanded upon release in pressure exactly in accordance with Boyle's law, the pressure decline curve would merely be a straight line through the original reservoir pressure and the May 31, 1954 reservoir pressure plotted against cumulative production as of May 31, 1954. However, since natural gas does not conform exactly to Boyle's law, the compressibility factor had to be considered. Calhoun shows that reservoir pressure (P) divided by the compressibility factor for the gas (Z) at reservoir conditions will plot as a straight line against cumulative production.[11] Compressibility factors were, therefore, computed for the two above reservoir pressures and a straight line plot made between the two P/Z points thus determined. The accuracy of the curve was checked analytically and original gas calculated to be 289 billion standard cubic feet. The reservoir pressures as they would be measured both in the reservoir and at the surface (Figure 4) were computed from the P/Z curves, using compressibility factors and values for the pressure due to the weight of the gas column as are shown graphically in Figures 7 and 8.

The 289 billion standard cubic feet of gas, as calculated to have been originally in the reservoir, at first appeared high, considering the present low production rate from the wells. An additional calculation was, therefore, made to determine the porosity of the sand, using 42,000 acres which has been estimated as the area of the reservoir, and an average sand thickness of 17 feet as estimated from the few well records showing this information. The porosity thus calculated came to 4.18 per cent. This porosity certainly does not appear to be excessive, considering the nine per cent and 8.34 per cent porosities found, respectively, for Oriskany sand samples blown from wells in the Tioga[12] and the Leidy gas fields.[13]

In consideration of the above, the 289 billion cubic feet does not appear to be excessive. An additional similar calculation of reserves was made, however, using the absolute minimum feasible pressures for block areas as of May 31, 1954. This calculation showed 255 billion standard cubic feet as the original gas content of the reservoir. The original calculation is considered to be the more accurate.

### V. Operations

### A. Determination of Average Well Productive Capacity

The equation $Q = C(P_f^2-P_s^2)$ as described in the Bureau of Mines Monograph 7 is also applicable to groups of wells.[20] The average well productive capacity coefficient, C, may therefore be obtained by averaging the C's computed for each well by dividing Q by $(P_f^2-P_s^2)^n$. Values for Q and for $P_{wh}$ are known as

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*Derived, using gas law equations, slightly inaccurate as the Z is based on the well-head pressure instead of the average pressure in the well.

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each well is completed and an open flow test is made. Since the value of n was not known, it was necessary to average the production rates (Q) for wells producing under the same $(P_f^2-P_s^2)$. Further, since little confidence could be placed in the accuracy of the lower pressures, it was decided to use wells showing well-head pressures near 3,500 pounds per square inch. Thirty such wells showed an average Q of 7,300M cubic feet per day. The pressure due to the weight of the column of gas in these wells averaged about 500 pounds per square inch, bringing the $P_f$ value to 4,000 pounds per square inch. Since $P_s$ can be neglected for these large-hole high-pressure wells flowing against atmospheric pressure, 7,300 (Q) can be plotted against 16,000,000 $(P_f^2-P_s^2)$ on logarithmic paper as is shown by point A in Figure 6. This gives one point on the logarithmic plot, but does not of course show the slope of the line which can be used to determine values of Q at different values of $(P_f^2-P_s^2)$. It was decided to use an n value of one (viscous flow) in order to simplify calculations and to preclude the exaggeration of the adverse effects of production practices as is brought out in Section V, B and C. Using this n value of one, the coefficient (C) for the 30 wells came to .456. These values of C and n were justified by an average value of C equal to .45 for 127 wells on which the recorded data appeared to be the most accurate. The value of C for each individual well in this case was obtained by dividing the flow rate (Q) by $(P_f^2-P_s^2)$, $P_f$ being the closed-in individual well-head pressure plus the pressure caused by the weight of the gas column, and $P_s$ again neglected.

Readers might be interested in the calculation of average permeability where the value of C equal to .456 was substituted in the Darcy's law radial flow equation for viscous flow. Though a rough assumption had to be made for the drainage radius and though the flow may not be considered as radial in all cases, the computed permeability of 4.05 millidarcies as compared to the estimated permeability of ten millidarcies tends to substantiate the assumption that the value of C is not excessive. Two samples blown from wells in the Leidy gas field averaged 10.9 millidarcies.[21]

In consideration of the above, the curve AB in Figure 6 may be considered to represent the production rate that could have been expected from the average well with decreasing values of $(P_f^2-P_s^2)$ had the physical characteristics of the well and the producing formation remained constant, and had the wells been so spaced as to have the average formation pressure acting on each well.

### B. Effect of Well Spacing and Production Practices on Production Rate

As pointed out in the previous section, curve AB (Figure 6) represents the declining production rates with declining $(P_f^2-P_s^2)$ values that could have been expected from average, undamaged, properly spaced wells. Curve CD (Figure 6) represents the actual average production rate per well with declining average reservoir pressures as shown in Figure 4. Points on curve CD were determined by dividing the total monthly production rates by the average number of producing wells as of the date indicated and plotting these rates per well against the $(P_f^2-P_s^2)$, $P_f$ being considered as the formation pressure shown by Figure 4 and $P_s$ being dependent upon the line pressure and is estimated as 600 pounds per square inch. The deficiency in production rate per well for any value of $(P_f^2-P_s^2)$ is represented by the horizontal distance between the two curves. This loss can be attributed to local pressure depletions in densely drilled areas and to physical damage to wells brought on by the rapid production rate.

Production losses caused by water coning, well caving, etc., cannot be well illustrated from the data available, although it would be a simple procedure to shut in wells occasionally and to plot the Q versus the $(P_f^2-P_s^2)$ on logarithmic paper. A line through successive points thus obtained would indicate whether or not a well is being damaged. A curve that bent toward the pressure axis would be indicative of water coning or other factors hindering deliverability. If only two points are available, and a line through the two points has a slope greater than one (more than 45 degrees to the pressure axis), it will, in the authors' opinion, be indication of well damage. This procedure was attempted for the few state wells on which records

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could be found showing shut-in pressures sometime after their original gaging. However, curves thus obtained only served to prove the inadequacy and inaccuracy of recorded data. One curve showed a reverse slope, indicating lower flow rate with increasing formation pressure.

The Bureau of Mines back-pressure method for analyzing the deliverability of gas wells is a much more thorough and detailed procedure than that described above. Far greater benefits than that discussed above may also be derived from their method, although it requires the restricting of a well's flow for considerably more time than production practices in Pennsylvania permit.

### C. Estimated Losses in Ultimate Recovery

Although it is impossible to predict the ultimate gas recovery from this reservoir with any degree of accuracy, it is fairly obvious in view of the declining production rate that an uneconomical production rate will be reached long before 289 billion cubic feet of gas have been produced.

Curve DE, Figure 6, shows a recent increasing rate of decline in production rate. This may be due to a variety of factors, such as

1. Water fingering cutting off relatively high pressure gas zones.
2. Water coning near the well bore, reducing the effective sand thickness.
3. Water condensation, reducing the effective permeability to the gas.
4. Water accumulation in the well bore.
5. Well caving.
6. Structural conditions within the reservoir.
7. The temporary shutting in of an increasing number of wells (since the rate is based on the number of producing wells as drilled rather than the actual number in operation).
8. Almost total pressure depletion in densely drilled areas.

It is the authors' opinion, however, that conditions in the reservoir may soon stabilize and that the flow rate after that time will continue in a directly proportional relationship with ($P_f^2$-$P_s^2$); at least this is the best that can be expected. This is illustrated by the curve EF, Figure 6. Though there is little chance that this curve will hold true to the abandonment date, it is not unreasonable to expect that it will hold approximately true for the next few years. This curve may be used in conjunction with the reservoir pressure curve (Figure 4) to provide a trial and error means for predicting future production and production rates. The dotted portions of the curves (Figure 3) were derived in this manner, considering a gradually decreasing value of $P_s$ to zero in the year 1959. By the end of the year 1959 there should have been about 240 billion cubic feet of gas produced from this reservoir.

In consideration of curves AB and EF (Figure 6) and assuming a minimum economic flow rate (Q) of 50MCF per day at zero back pressure ($P_s$), the reservoir could be expected to be abandoned at an average pressure ($P_f$) of 632 pounds per square inch, whereas in the "ideal" case the abandonment pressure would be 316 pounds per square inch. This, according to Figure 4, reflects a loss of about 22 billion cubic feet of gas due to inefficient production practices.

Actually, it is anyone's guess as to just how far into the future this reservoir will produce gas at an economic rate. Most likely there will be numerous wells capable of producing gas at an economic rate for many years to come. It is highly probable, however, that water fingering and coning has or will cut off relatively high pressure zones within the reservoir, and that a reduced effective permeability to gas caused by water coning and condensation will seriously curtail production and reduce the ultimate recovery. An estimated loss of approximately 20 billion cubic feet of gas is considered to be conservative.

## VI. Evaluation of Results

### A. Operational Aspects

Although this study has developed no absolute proof that there will be substantial losses in ultimate recovery of gas from this reservoir, it does indicate that such losses are very likely and pre-

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sents definite proof that a great amount of manpower and materials have been unnecessarily expended. Curves AB and CD (Figure 6) show that actual production per well was only about 35 per cent of what might have been expected from the properly-spaced average well. or that about one-third of the wells, if properly spaced and undamaged, should have given the same production rate. As was pointed out in Section V, A, this figure is based on a conservative estimate of the slope of the logarithmic curve AB (Figure 6) equal to one. It is possible that this curve could have had a slope of less than one, showing an increasingly wide separation between the "ideal" and "actual" curves with decreasing pressures, and therefore an increasingly poorer comparison of the actual well production rate with that of the ideal.

The ideal number of wells can only be determined by an economic balance of a great many factors, such as recoverable gas in place, drilling costs, back pressure required to prevent damaging the well or the producing formation, market demands and commitments and others. The back pressure required can be determined accurately by the Bureau of Mines method, but even this is subject to economic considerations. It may, for example, be more economical to permit minor damage to the well than to hold the back pressure sufficiently high to prevent damage entirely. Some states force the application of back pressure by restricting gas production to 25 per cent of open flow capacity. However, this restriction is also intended to prevent gas production in excess of market demands, and there is no reason known to the authors why Pennsylvania should restrict production to this rate if it can be shown that significant damage will not occur to wells producing at higher capacities. All of the above factors can best be weighed and applied through a unit operation plan, assisted perhaps by a well-spacing regulation.

It is probable that no more than two billion cubic feet per month would have been the ideal production rate from the Driftwood-Benezette field. Gas companies taking gas from this field must contract for vast quantities of gas from the Southwest to meet commitments during the winter months. Furthermore, the nature of pipeline operations as well as economic factors in the producing Southwest demand the establishment of long-term contracts with little or no seasonal variations in gas deliveries. This requires the delivery of large quantities of gas to this area during the summer months which must be stored in underground reservoirs. It is therefore obvious that the most economical rate to extract gas from this field would be a long-term rate necessary to augment deliveries from the Southwest with a minimum of storing required.

According to curve AB (Figure 6), two billion cubic feet per month could have been produced early in the productive life of the field ($P_f$ = 4,600) with 27 wells producing at 25 per cent of open-flow capacity, and with 100 wells at this capacity five years later when the 120 billion cubic feet produced would have caused the reservoir pressure to drop to about 2,400 pounds per square inch (Figure 4). At 50 per cent open-flow capacity, only half of these wells would be required, and 100 wells would produce two billion cubic feet or more per month until 175 billion cubic feet of gas had been produced. Assuming that the flow rate could reach a maximum at the lower pressures without causing significant damage to the wells or the formation, 100 wells would sustain the 2 billion cubic feet per month rate for almost nine years or until 210 billion cubic feet of gas had been produced. Does not this appear more efficient and logical than has been the actual practice of drilling around 300 producing wells to obtain the flow rate shown in Figure 3?

The above comparison of actual practices with those which might have been employed under unit operations or under well spacing regulations does not show a comparison of ultimate recovery losses. It was illustrated in Section V, C that there should be at least 20 billion cubic feet of gas lost because of inefficient production practices. Though structural conditions in the reservoir might not permit such high ultimate recovery in either the actual or the ideal case, it is probable that unit operations or ade-

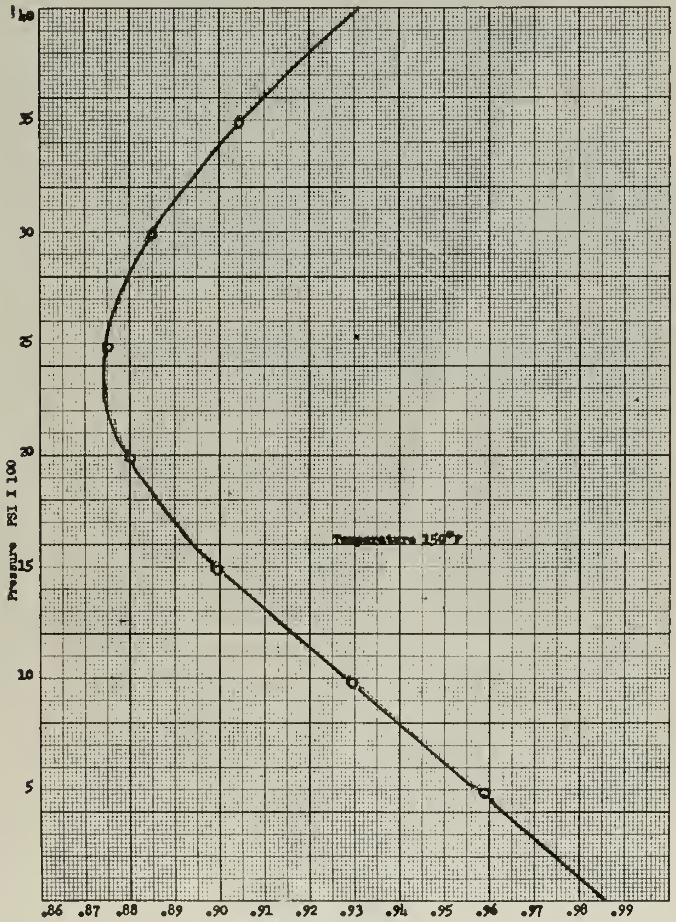

Figure 7—Compressibility factor vs. Pressure

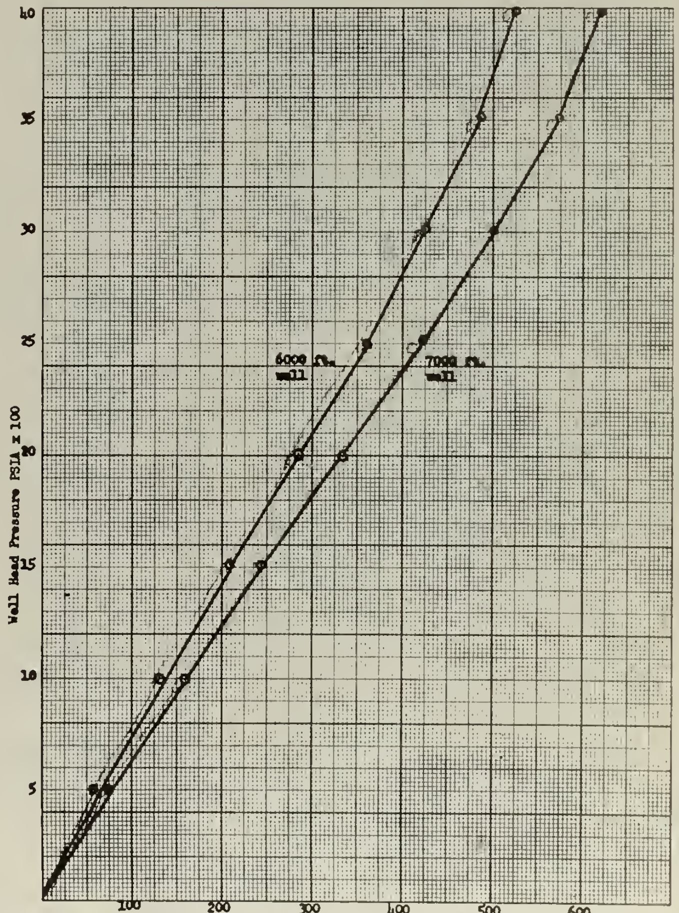

Figure 8—Pressure due to weight of gas column of well-head pressure

quate well spacing regulations would provide for more efficient exploration and thereby for a production rate closely approaching that shown by the curve AB (Figure 6).

### B. Economic Aspects

**1. General**

The economic aspects of production practices may be illustrated roughly as follows:

(a) Before this reservoir is abandoned there will probably have been 300 producing wells drilled—200 more than is conservatively estimated to be the ideal as stated in the previous section. At $75,000 per well, this will amount to an unnecessary expenditure of $15,000,000.

(b) It is estimated that at least 60 billion cubic feet of gas will have been stored and re-extracted beyond that which would have been necessary at the two billion per month rate. At an estimated cost of five cents per thousand cubic feet for storing and re-extracting, this will amount to $3,000,000.

(c) Twenty billion cubic feet of gas estimated to be lost due to open flow production practices, at an estimated net value of about ten cents per M cubic feet[22] will amount to a loss of $2,000,000.

(d) It is estimated that about 75 billion cubic feet of gas would have increased in value by at least two cents per M cubic feet had it been possible to produce this gas on a seasonal contract or at a slower rate. This will amount to $1,500,000.

(e) There have been numerous relatively minor excessive expenditures, such as expenses for operating compressor stations, additional well maintenance costs due to open flow production practices, excess gathering lines, etc.

In view of the foregoing illustration, it is reasonable to assume that $20,000,000 have or will be wasted by the production practices employed in the Driftwood-Benezette gas reservoir. Furthermore, a large portion of these losses will be paid by the consumer in the form of high gas prices or in taxes to make up for the losses from state-owned tracts.

**2. Private Landowners**

Much of the land overlying this reservoir is privately owned small tracts of one acre or less. Such a landowner's fair share of the gas, considering 40,000 acres total and 280 billion cubic feet of gas as recoverable, is 7,000 M cubic feet. At one-eighth royalty this figure is further reduced to roughly 900 M cubic feet, which would amount to $247.50 at the current price of 27½ cents per M cubic feet. It is conservatively estimated that many small tract landowners have or will receive at least a hundred times this figure. Their excess profits obviously resulted in losses from less densely drilled areas, which in this field are mostly state-owned tracts.

### Conclusion

It is concluded that there have been about 200 excess wells drilled in the Driftwood-Benezette field; that there could not possibly have been a fair and equitable distribution of the gas among the various landowners; that very probably there have or will be large quantities of gas left in the reservoir because of open-flow production practices; that sound engineering principles are not observed in gaging wells and in evaluating their performance, and that all of these are directly attributable to the lack of petroleum regulatory statutes in Pennsylvania. It is further concluded that the general public supports a large share of the inequities, gas losses and excess expenses either in higher gas prices or in decreased revenue from publicly owned land.

The obvious recommendation, therefore, is that the citizens of Pennsylvania demand the enactment of state statutes which will prevent this waste of manpower, materials, and petroleum resources, and which will insure the protection of correlative rights of landowners.

The details of the varied petroleum conservation measures and unitization statutes are beyond the scope of this paper. The average citizen, however, should not be so much concerned with these details as by the fact that nothing is being done to remedy the current inefficient and unfair production practices. Citizens should place their faith in an Oil and Gas Committee appointed for the purpose of recommending appropriate conservation and unitization statutes

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It is additionally recommended that the state immediately institute a program to acquire, compile and correlate information needed for accurate engineering studies, and to make this information readily available to all interested parties. No information relating to well production should be confidential. The very least that should be done is the enactment of a law requiring that all gas wells be shut in for a minimum of 48 hours once a year and that shut-in pressures be recorded and reported to an appropriate state regulatory body. Open-flow capacities, or flow rates against stated back pressures, should be recorded at the time wells are shut in, and likewise reported. Though this information will not suffice for accurate computation of the wells' performance by the Bureau of Mines back-pressure method, it will provide for considerably more accurate engineering studies than are currently possible. This recommendation would be superfluous if adequate petroleum conservation laws were enacted, for effective conservation presupposes a requirement for accurate knowledge of both the gas reservoir and the producing wells, which can only be gained from extensive and accurate data.

### Acknowledgments

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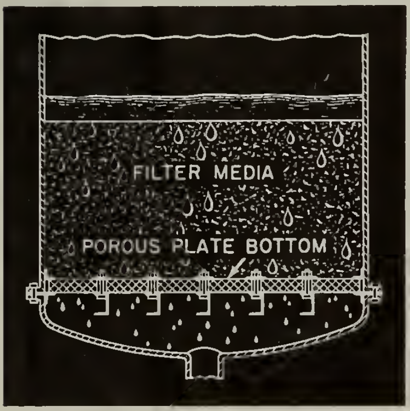

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# NEERING STUDY OF THE DRIFTWOOD-BENEZETTE
# GAS FIELD IN PENNSYLVANIA

by

Glen Brandon Connally

B.S., Agricultural and Mechanical College of Texas, 1938

Submitted to the Graduate School of the University
of Pittsburgh in partial fulfillment of the
requirements for the degree of
Master of Science

Pittsburgh, Pennsylvania
1955

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## FOREWORD

This paper presents a petroleum engineering approach to the evaluation of production practices employed in the Driftwood-Benezette gas field in Pennsylvania, and compares the results of such practices with those which might have been accomplished had the field been developed and operated in the most efficient manner, or in accordance with modern petroleum conservation laws.

The Driftwood-Benezette gas field is important to this study only in that it provides a means for illustrating production practices generally employed in all Pennsylvania gas fields. Therefore, no attempt has been made to set forth details of engineering and geologic interest not closely related to production practices.

Grateful acknowledgment is made to the engineers and geologists of the Manufacturers Light and Heat Company and the New York State Natural Gas Company for their cordial reception of the author in his quest for information and for their time and effort expended in making information available; to Professor H. G. Botset, Head of the Petroleum Engineering Department, University of Pittsburgh, and Professor P. F. Fulton, Associate Professor, Petroleum Engineering Department, University of Pittsburgh, for the suggestion of the study and for their helpful comments and recommendations; and to the U. S. Naval Postgraduate School, Monterey, California, for their sponsorship of the petroleum logistics curriculum at the University of Pittsburgh through which the author was provided with the basic opportunity for preparing this paper.

# I. INTRODUCTION

Petroleum production practices in Pennsylvania have remained the same in principle since the discovery of the Drake well in 1859. There are no laws restricting petroleum production even though it is a well known fact that "wide-open" flow may cause great underground losses of oil or gas; moreover, there are no laws protecting landowners' correlative rights -- the right to enjoy the use of one's property so long as this enjoyment does not do injury to others.[1]

There have been several proposals[2] for petroleum conservation laws which would require or encourage the development and operation of a petroleum reservoir as a single unit rather than on the wasteful and costly basis of "every man for himself." None has been enacted, however, and it appears that Pennsylvania may become the leading oil and gas producing state where no such laws are in effect. It is indeed a mystery why no such laws have been enacted. One would think that Pennsylvania, the founding state of the petroleum industry, would have been a leader in petroleum regulatory law. There must be some merit to petroleum conservation and unitization laws, for no state has ever repealed such a law. The Interstate Oil Compact Commission, which through engineering, research, and other committees functions to advise the various states on petroleum regulatory measures, has recommended the enactment of a unitization law.[3] Does it not seem logical that there should be a minimum waste of petroleum resources, and that a landowner should be permitted to recover his fair share of the oil or gas underlying his land, and only his fair share, without the drilling of unnecessary wells?

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[1] References are listed in the Bibliography.

Perhaps many Pennsylvanians are not acutely aware of the waste of their petroleum resources or the infringement on their correlative rights caused by maximum-rate production practices employed in Pennsylvania. This study has been made in an attempt to illustrate, quantitatively, the effects of such practices as they relate to natural-gas production.

The Driftwood-Benezette field provides a good example for illustrating natural-gas production practices in Pennsylvania. This field was intensely drilled soon after its discovery and allowed to produce at maximum rate. Each landowner had to get his gas to the surface before his neighbor drained it away. It is the author's opinion that this caused the drilling of about 200 more wells than would have been necessary to produce the field efficiently, and that open-flow production will cause the underground loss of at least 20 billion cubic feet of gas, with a net value of approximately $2,000,000.

Unfortunately, accurate results cannot be obtained from the data available. Throughout this study, however, the author continually strove to favor the use of results and assumptions which would not exaggerate the adverse effects of existing production practices.

## II. INADEQUACY OF ENGINEERING DATA

It became apparent at the beginning of this study that the lack of petroleum regulatory laws has resulted in an inadequacy of engineering data.

It is impossible for engineers to make accurate engineering studies, upon which plans for future gas production, transportation, storage and marketing must be based, without complete and accurate engineering information. Furthermore, this information must be readily available, at a central source, to all interested parties.

In 1935 the Bureau of Mines introduced a method for computing gas-well capacities and for applying this information to production practices.[4] The basic equation[5] set forth in that report is used throughout the natural gas producing industry—even in Pennsylvania—yet the data available on Pennsylvania wells for use in that equation are entirely inadequate for accurate calculations.

Though there are no laws preventing operators from obtaining these data on their own wells, few will voluntarily close in a well or restrict its production while their neighbor drains gas from under their land at a maximum rate. Further, in order to provide maximum benefit, this information must be standardized and compiled under a well organized program, enforced by a central authority and maintained readily available at a central source.

This lack of adequate information has obviously lead to inaccuracies in much of the data that have been obtained. Probably the greatest inaccuracies have been in measuring the shut-in pressures of the wells, the very heart of the information used in petroleum engineering studies.

Another source of difficulty to an engineer is the confidential nature of production information on privately owned wells. An accurate evaluation of a well's performance requires the comparison of that well with other wells in the near vicinity, and an evaluation of the reservoir as a whole may require the use of performance data on any well in the reservoir.

Specific examples of either inadequate or inaccurate information encountered during the course of this study are listed as follows:

1. Shut-in well pressures are often inaccurate. Most wells were shut in for less than 24 hours when their pressures were recorded, some for only an hour or less.

2. The entire reservoir has never been shut in and the average pressure recorded, nor are individual wells shut in periodically for this purpose. One accurate reservoir pressure, after sufficient gas had been produced to show a pressure decline, would have been sufficient to compute total gas reserves. As the situation stands, operators are merely guessing at gas reserves, and no one will ever know how much gas is lost due to production practices.

3. Production information on privately owned land is confidential and, therefore, not available to the public or to all interested producing companies.

4. No records could be found showing shut-in pressures for wells on more than one occasion after having been cut in to the pipeline. This information is necessary in order to determine a well's performance characteristics and behavior as described in Section V, A and B.

5. No one producer or regulatory body has all the data on all the wells in the reservoir. Absence of monthly production rates for all wells

is the most important example of this inadequacy. Other missing information might be as follows: The drilling method used, whether or not a well was shot, original well-head pressures and shut-in time, and whether or not a well had been abandoned.

6. The reservoir temperature has never been measured.
7. Very few reservoir sand thicknesses have been recorded.
8. Well locations are not recorded in a standard form.
9. Neither the porosity nor the permeability of the sand have ever been measured.

In view of the above, the results brought out in this study are not nearly so accurate nor significant as they otherwise might have been. Perhaps the inadequacy of this study will serve to indicate the necessity for such state statates as will provide for the compilation of information necessary to conduct accurate engineering studies.

## III. HISTORY OF OPERATIONS

### A. The Reservoir

The Driftwood-Benezette gas field is the largest known gas field in Pennsylvania, covering about 42,000 acres in Elk, Cameron, and Clearfield counties. Production is from the highly faulted Oriskany sandstone, which in this area is mostly "medium-grained, light gray, quartzose, slightly calcareous."[6] The Oriskany is capped by the Onondaga limestone formation.

Figure 1 shows the approximate area of the reservoir superimposed on a contour map on the Oriskany sandstone as constructed by Fettke.[7] Figure 2 shows locations of all wells numbered in the sequence in which they were completed or drilling operations abandoned, although numbers for dry holes have been omitted on the drawing. Pertinent information on each producing well is shown in Appendix I.

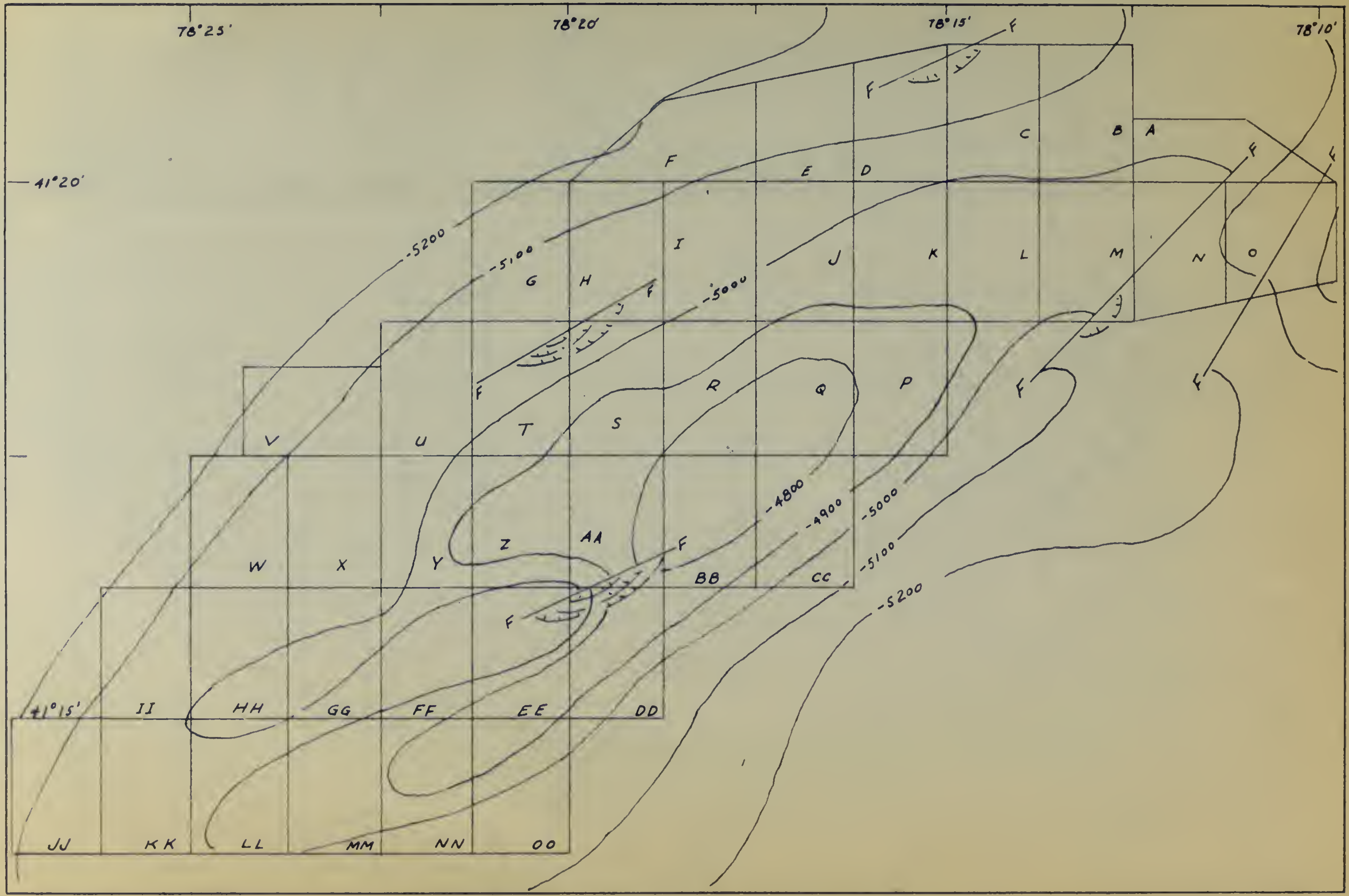
It should not be construed that the reservoir has such a jagged boundary as is indicated by the block areas in Figures 1 and 2. These blocks established by the author were used to compute the average reservoir pressure as described in Section IV.

This field is located on the Driftwood anticline, the highest point on which is the Driftwood dome, located about one mile northeast of the town of Driftwood. This dome is not shown in Figure 1 since the dome itself proved to be outside the productive boundary of the reservoir, as indicated by the numerous dry holes shown just to the northeast of the reservoir in Figure 2.

The northeast or Driftwood end of this reservoir was discovered first. The discovery well was Sylvania's S. C. Eaton No. 1 (Figure 2,

well 1-A) completed September 15, 1951. Since this well was situated relatively low on the southwest plunge of the Driftwood dome, subsequent tests were made high on the dome in and around the town of Driftwood, none of which proved productive apparently because of a tight sand stratigraphic closure at the northeast end of the reservoir. Development was then shifted down the plunge to the southwest.

The Keta Oil and Gas Company's Charleroi Mountain Club No. 1 (Figure 2, well 57-S) on the Benezette dome opened the Benezette end of the reservoir in December, 1952. Then in March, 1953, the Benezette Valley Development Company brought in the William Woodring No. 1. (Figure 2, well 69-F) This well was extremely importent in that it is some 300 feet lower on the flanks of the Benezette dome than the Charleroi well, indicating that the Driftwood-Benezette field was much larger than had previously been estimated.[8] This led to the furious drilling race between private landowners which resulted in the dense well pattern as shown in Figure 2, areas F, G and H. Presumably, if the areas to the south had not been mostly state-owned land, the entire field would have been drilled into a similar pattern.



Contours on Oriskany Sandstone

Figure 1 Structure Map Driftwood-Benezette Gas Field

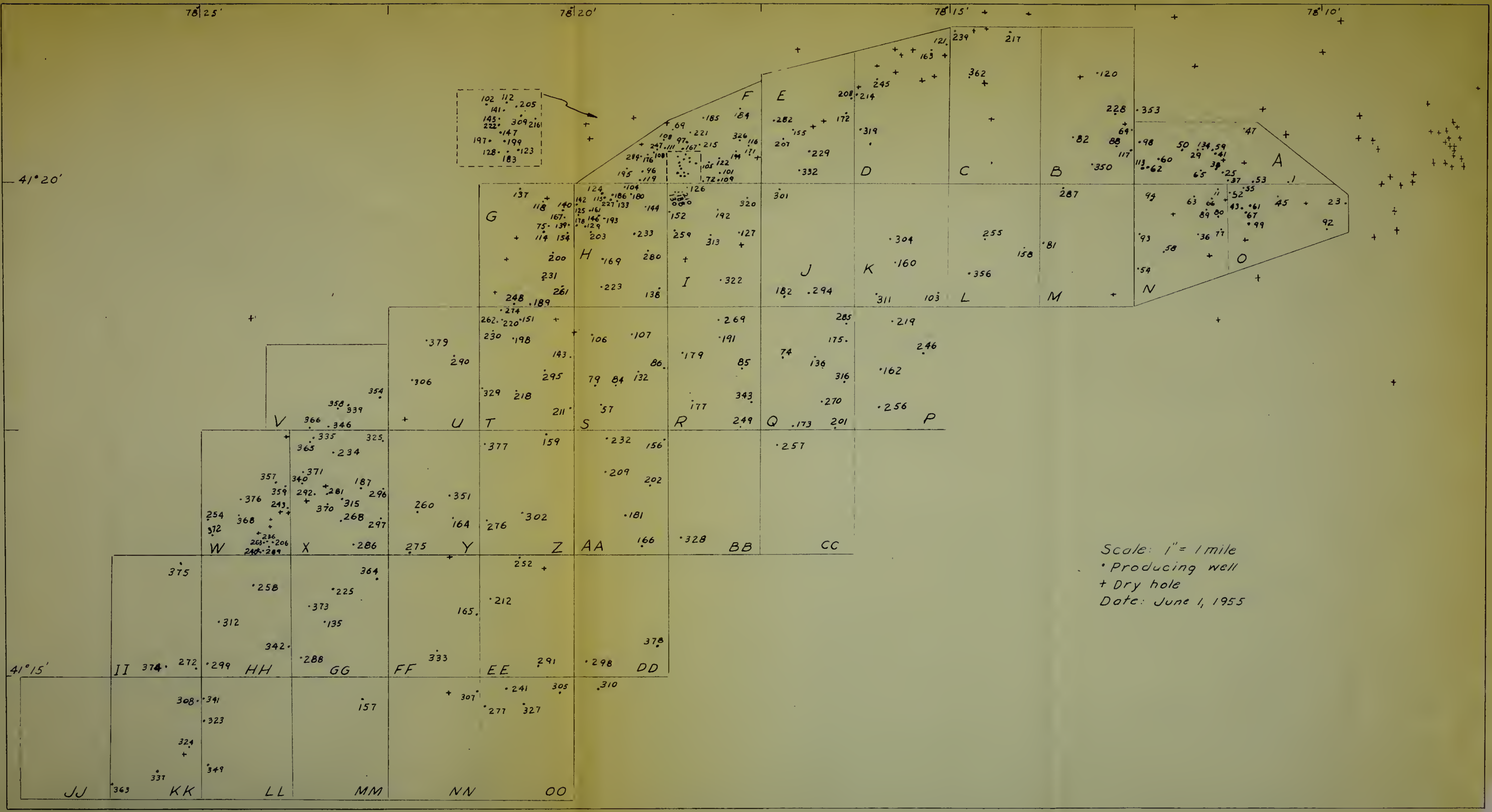


Figure 2. Block Area Map, Driftwood-Benezette Gas Field

## B. Drilling and Production Practices

### 1. Drilling and Casing

Drilling operations reached a peak in August, 1953 when 22 producing wells were brought in. The rate then dropped slightly and leveled off at about fifteen to twenty wells per month until July, 1954, at which time there began a rapid decline in the drilling rate. Appendix IV shows a detailed breakdown of the wells by months.

Most of the early drilling was with cable tools which averaged about sixty feet per day. Rotary drilling was later used, which averaged about 180 feet per day; however, lost circulation and completion problems were frequently caused by the high density (17 pounds per gallon) drilling mud. Completion problems were often overcome by drilling-in with cable tools, but a more recent practice of using air-rotary drilling with gas completions has been highly successful in eliminating both of these difficulties. The air-rotary has shown a penetration rate of about twice that of the regular rotary.[9]

All methods employ the practice of setting a seven-inch O. D. casing about ten feet into the Onondaga limestone, and then drilling a 6 1/8 inch hole into or through the Oriskany sandstone.

Open-flow capacities of wells are measured with pitot tubes while the gas is discharged to the atmosphere. Shut-in pressures are generally recorded after wells have been closed in for 24 hours, although the rush to cut the wells into the pipeline frequently permits only a few hours shut-in time.

### 2. Production Practices

Little can be said of production practices except that wells are cut in to the pipeline as quickly as possible and permitted to flow at

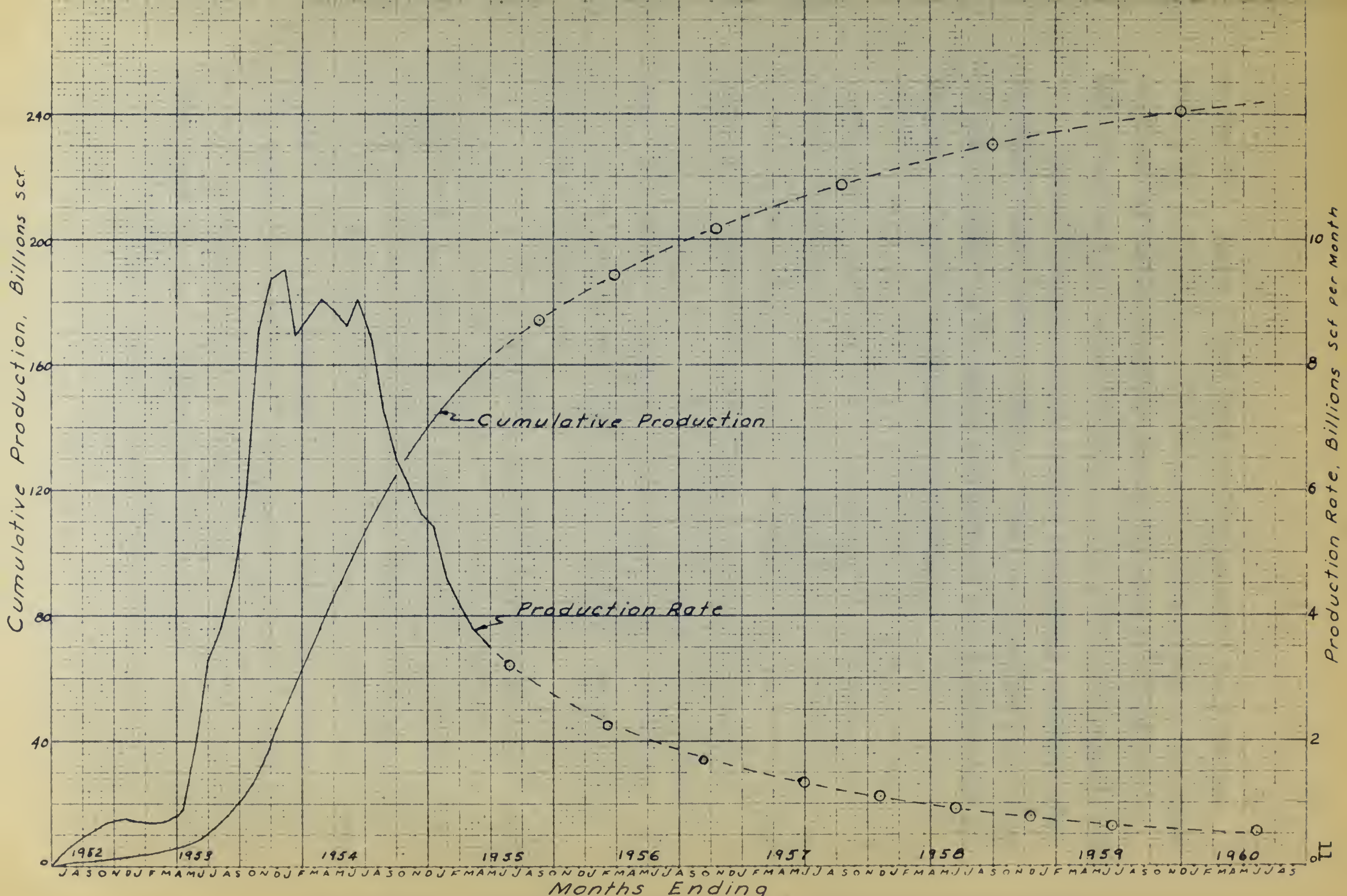


Figure 3. Cumulative Production & Production Rate vs. Time

maximum rate. Figure 3 shows the cumulative production and production rate of the field plotted against time. The dotted portion of the curves represents the predicted recovery and recovery rates as explained in detail in Section V, C. Actual production figures are shown in Appendix III.

There has been no evidence of water drive during production from this field. There have been occasions of wells being drowned out by water, but this difficulty has frequently been relieved, at least temporarily or partially, by shutting in the wells for a few days.

## IV. DETERMINATION OF RESERVES

An accurate determination of gas reserves in a reservoir can be made only when accurate reservoir pressures are known. Since the Driftwood-Benezette reservoir has never been shut in, in order to determine a reservoir pressure, and since pressures for individual wells are not periodically recorded, any method used in computing reserves is largely guesswork. The original reservoir pressure was most probably about 4020 pounds per square inch gage, as measured at the well head. Obviously, no other pressure would be needed to compute reserves if the boundaries of the reservoir, the porosity, the per cent water saturation, and the sand thickness were known. However, in view of the highly faulted structure of this reservoir, the probable wide variation in porosity, and the doubtful boundaries as estimated, the only practicable method for determining reserves is by the use of declining reservoir pressures with cumulative production, as is shown graphically by Figure 4, and as explained in detail later in this section.

The only course for determining the average reservoir pressure lay in averaging pressures by areas, area pressures being obtainable from original pressures for new wells as shown in Appendix I. It is believed that the boundaries of the reservoir are sufficiently well established so that it can be divided into areas as shown in Figure 2, and that each area has roughly the same average porosity and sand thickness. Though this may not be entirely true, the method of averaging area pressures in order to determine the over-all reservoir pressure is not overly demanding of an accurate reservoir area, and it is not necessary that the sand thickness or porosity be known, provided each area is assumed to have equal pore

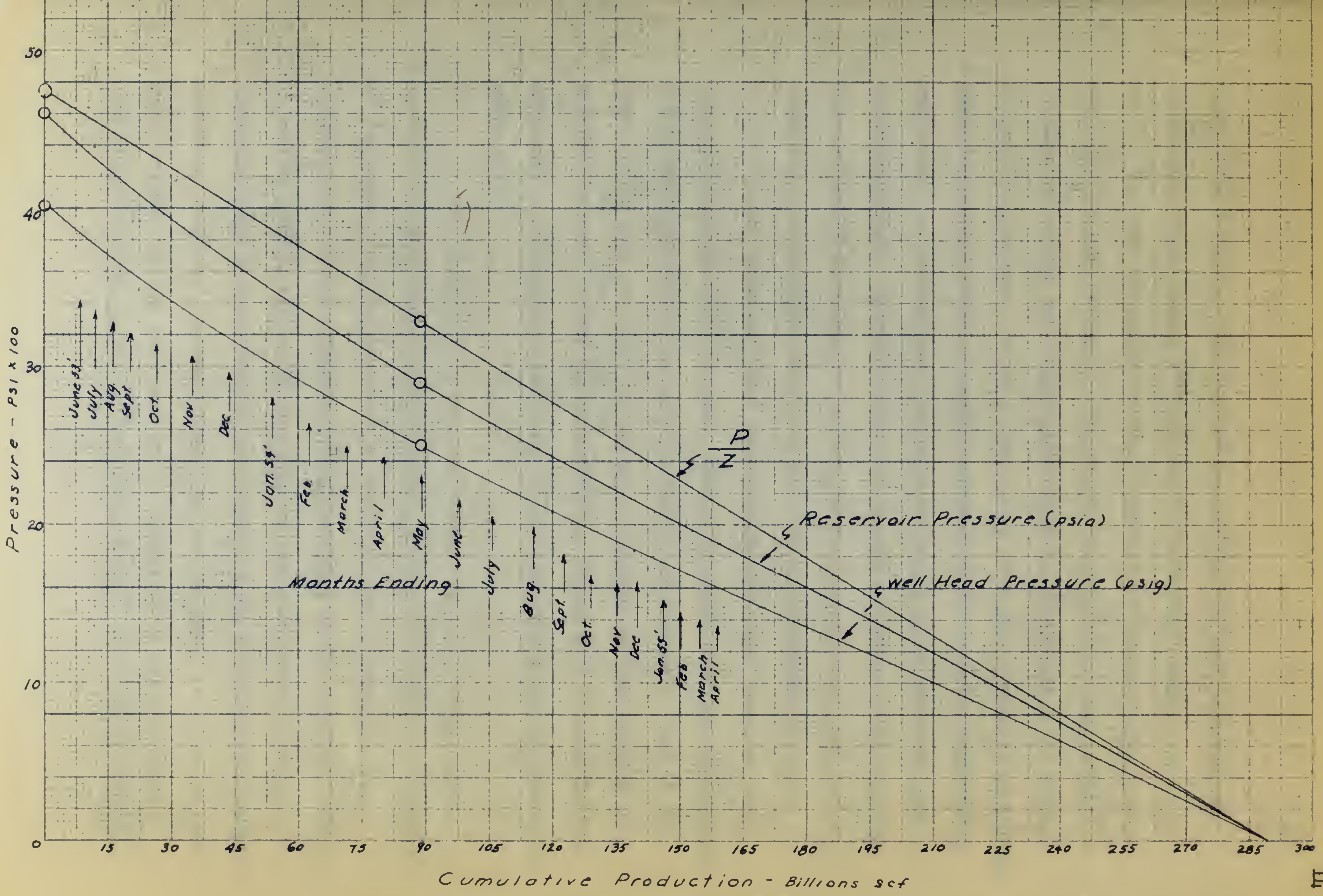


Figure 4. Pressure Decline with Cumulative Production

space. The reservoir area as shown is comprised of forty-one approximately equal-sized blocks of about one thousand acres each.

The only difficulty lay in determining the average area pressures at a selected date or dates. The pressure recorded for a well drilled in the area on or near the selected date could not be used with any degree of accuracy, for often the well would be in such close proximity to another that its pressure would be greatly affected, or the pressure shown for a well drilled at a later date in the same vicinity might have been considerably higher. Many additional factors had to be considered, such as the location of the wells in the area, their distance apart, the length of shut-in time compared to flow rate, and pressures in adjoining areas.

It soon became apparent that many recorded well pressures were lower than they should have been. Most of the wells were shut in for less than twenty-four hours when their pressures were recorded. This is far short of the time estimated to have been necessary for the pressure to stabilize in sand of such low permeability. It has been illustrated that pressures recorded after three days may still be well below the stabilized pressures.[10]

It was impossible to select any single date near which, during the early and late stages of development, wells were drilled in a majority of the areas. This required such an extensive use of estimated area pressures that little reliability could be placed in the computed average. It was, therefore, decided to determine the one most accurate average reservoir pressure which occurred well along in the productive life of the reservoir. Only one pressure, other than the original, is needed to compute reserves, and one good pressure is considered to be more accurate than a decline curve average of several poor ones. In order to determine

the most accurate pressure each block area was considered separately. Again, weighing all significant factors stated above, every instance in which a well pressure or several well pressures appeared to reasonably represent that for the block area was recorded under the date shown. When such pressures for all areas had been recorded, the widest coverage of area pressures fell near the date of May 31, 1954. That date was, therefore, selected for determining the over-all average reservoir pressure. In cases where a block area failed to show a pressure on or near that date, it was possible to interpolate between dates on either side of May, 1954 or to estimate the area pressure from those shown for surrounding areas. Well-head pressures thus determined are shown in Figure 5. The average of these gage pressures came to 2490 pounds per square inch.

The pressure due to the weight of the column of gas was computed as shown in Appendix II, using the equation

$$Pw = \frac{P_x ZRT\ 144}{MH} - .5Px\ ^*$$

where $Pw$ = well head pressure in pounds per square inch absolute,

$P_x$ = pressure due to the weight of the gas column in pounds per square inch,

$Z$ = gas compressibility factor at average temperature in the well bore and at well head pressure,

$R$ = gas constant,

$T$ = average temperature of the gas column,

$M$ = molecular weight of the gas,

$H$ = average depth of the reservoir below the surface.

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*Derived, using gas law equations, slightly inaccurate as the Z is based on the well head pressure instead of the average pressure in the well.

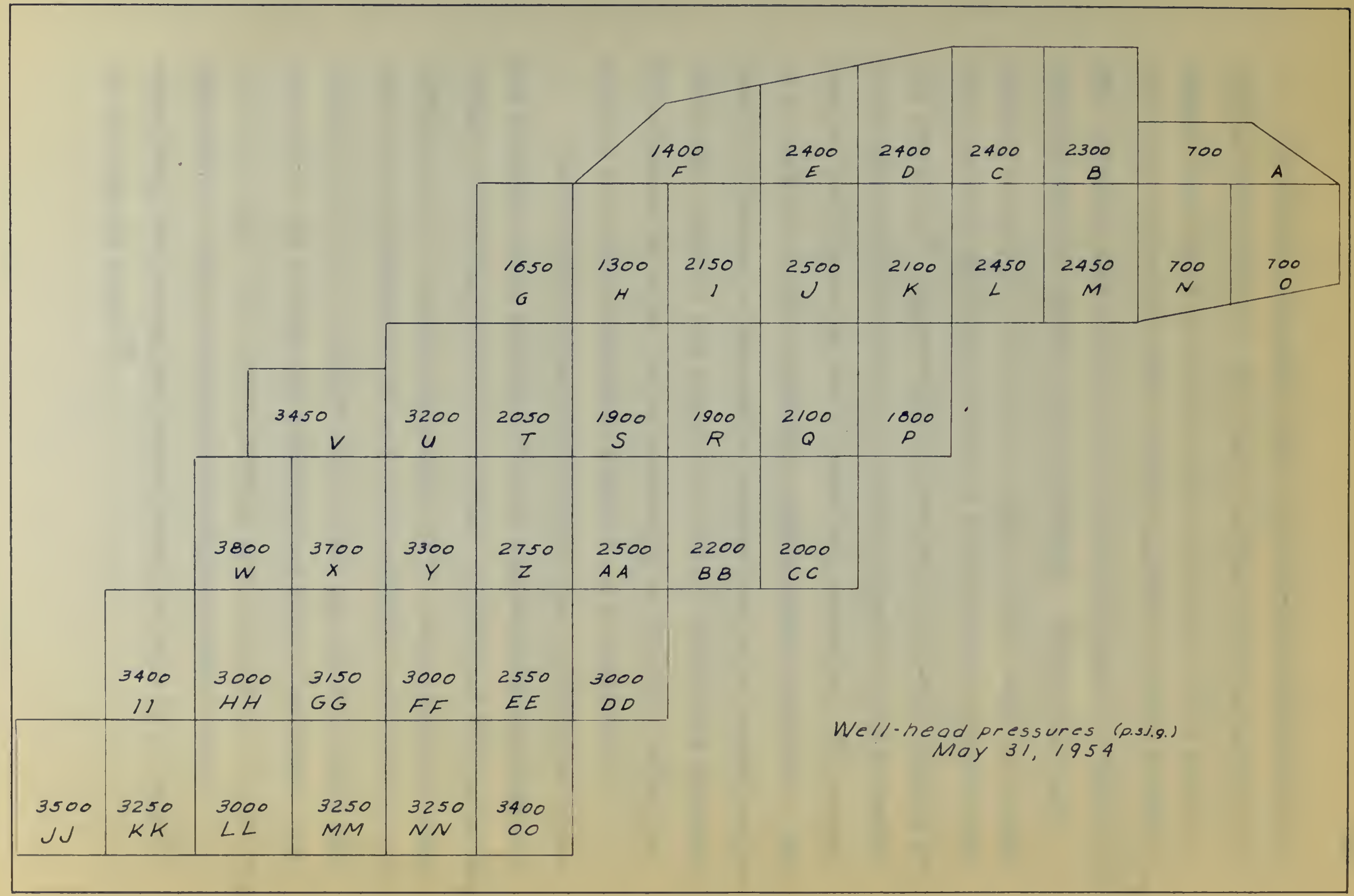

Figure 5. Pressures by Block Areas

If natural gas expanded upon release in pressure exactly in accordance with Boyle's law, the pressure decline curve would merely be a straight line through the original reservoir pressure and the May 31, 1954 reservoir pressure plotted against cumulative production as of May 31, 1954. However, since natural gas does not conform exactly to Boyle's law, the compressibility factor had to be considered. Calhoun shows that reservoir pressure (P) divided by the compressibility factor for the gas (Z) at reservoir conditions will plot as a straight line against cumulative production.[11] Compressibility factors were, therefore, computed for the two above reservoir pressures as shown in Appendix II and a straight line plot made between the two P/Z points thus determined. The accuracy of the curve was checked analytically, also as shown in Appendix II. The reservoir pressures as they would be measured both in the reservoir and at the surface (Figure 4) were computed from the P/Z curve, using compressibility factors and values for the pressure due to the weight of the gas column as are shown graphically in Figures 7 and 8, Appendix II.

The 239 billion standard cubic feet of gas, as calculated to have been originally in the reservoir, at first appeared high, considering the present low production rate from the wells. An additional calculation was, therefore, made to determine the porosity of the sand, using 42,000 acres which has been estimated as the area of the reservoir, and an average sand thickness of 17 feet as estimated from the few well records showing this information. The porosity thus calculated, as shown in Appendix II came to 4.18 per cent. This porosity certainly does not appear to be excessive, considering the nine per cent and 8.34 per cent porosities found, respectively, for Oriskany sand samples blown from wells in the Tioga[12] and the Leidy gas fields.[13]

In consideration of the above, the 289 billion cubic feet does not appear to be excessive. An additional similar calculation of reserves was made, however, using the absolute minimum feasible pressures for block areas as of May 31, 1954. This calculation showed 255 billion standard cubic feet as the original gas content of the reservoir. The original calculation is considered to be the more accurate.

## V. OPERATIONS

### A. Determination of Average Well Productive Capacity

#### 1. Bureau of Mines Equation

The Bureau of Mines has reported[14] that:

> "For normal gas wells there is a consistent relationship between rates of delivery of gas and corresponding pressures when the pressures in the sand are used as the basis for interpretation. Results of tests throughout the United States show that when the rates of delivery are plotted on logarithmic paper against $(P_f^2-P_s^2)$ - the respective differences of the squares of the formation pressure, $P_f$ and the pressure at the sand face, $P_s$ - the relationship is represented by a straight line, which may be expressed mathematically by the formula
>
> $$Q = C(P_f^2-P_s^2)^n$$
>
> where Q = rate of flow, M cubic feet per 24 hours,
>
> C = coefficient,
>
> $P_f$ = "shut-in" formation pressure, pounds per square inch absolute,
>
> n = exponent, corresponding to the slope of the straight line relationship between Q and $(Pf^2-Ps^2)$ plotted on logarithmic paper."

It is further pointed out in that report[15] that the value of n, or the slope of the logarithmic plot, would remain constant if no physical changes occurred in the well bore or in the producing formation which affected the productive capacity of the well.

This Bureau of Mines report recommends the above relationship as a means for analyzing the deliverability of gas wells. The procedure involves, essentially, the periodic shutting in of the well to determine the formation pressure ($P_f$), and then permitting the well to flow at decreasing back pressures ($P_s$) during which time the rate of flow (Q) is measured

for each back pressure. The logarithmic plot described above can be extrapolated to determine the open flow capacity of the well without the necessity of venting the well to the atmosphere and thereby wasting gas and probably damaging the well.[16] When flow rates so determined at periodic intervals fail to fall on the same straight-line logarithmic plot, it is indicative of changes occurring in the well or the producing formation, such as water coning, water condensation, well caving, etc. This procedure also provides a means for predicting flow rates at various back pressures and formation pressures, and for analyzing the effects of measures taken to increase a well's productive capacity.

A Bureau of Mines report[17] some nine years later carried an interesting discussion of the value of n as related to a similar exponent in an equation[18] for isothermal flow derived and confirmed experimentally by Muskat and Botset, where the latter had shown, in effect, that the value of n in the equation $Q = C(P_f^2-P_s^2)^n$ would range from 0.5 for wholly turbulent flow to 1.0 for wholly viscous flow. The Bureau of Mines report stated that it had been shown experimentally that the value of n ranged from 0.6 to 1.2 and that there was no significant bending of the logarithmic plot toward the pressure axis for increased values of $(P_f^2-P_s^2)$ and Q, as might have been expected.

It is significant to note, however, that the second Bureau of Mines report was based largely on results of tests set forth in the first report and that both field and experimental results[19] were obtained from highly permeable sands through which gas was flowing under relatively low pressures. It is further significant to note that many laboratory tests did show logarithmic plots that bent slightly toward the pressure axis with increasing values of Q and $(P_f^2-P_s^2)$, and that there appears to be

no confirmation in laboratory tests for values of n greater than one. One might, therefore, surmise that possibly there could be a significant bending of the logarithmic curve toward the pressure axis with greatly increasing values of $(P_f^2-P_s^2)$ and Q and that possibly the few cases during field tests where the value of n exceeded one resulted from physical changes occurring in the well bore or from inaccurate data. It is the author's opinion that values of n greater than one should be accepted with reservations, if at all.

## 2. Application of the Bureau of Mines Equation

The equation $Q = C(P_f^2-P_s^2)$ as previously described is also applicable to groups of wells.[20] The average well productive capacity coefficient C, may therefore be obtained by averaging the C's computed for each well by dividing Q by $(P_f^2-P_s^2)^n$. Values for Q and for $P_f$ as measured at the well head are shown in Appendix I. Since the value of n was not known, it was necessary to average the production rates (Q) for wells producing under the same $(P_f^2-P_s^2)$. Further, since little confidence could be placed in the accuracy of the lower pressures, it was decided to use wells showing well-head pressures near 3500 pounds per square inch. Thirty such wells showed an average Q of 7300 M cubic feet per day. The pressure due to the weight of the column of gas in these wells averaged about 500 pounds per square inch, bringing the $P_f$ value to 4000 pounds per square inch. Since $P_s$ can be neglected for these large-hole high-pressure wells flowing against atmospheric pressure, 7300 (Q) can be plotted against 16,000,000 $(P_f^2-P_s^2)$ on logarithmic paper as is shown by point A in Figure 6. This gives one point on the logarithmic plot, but does not of course show the slope of the line which can be used to determine values of Q at different values of $(P_f^2-P_s^2)$. It was decided to use an n value of one (viscous flow) in order to simplify calculations and to preclude the exaggeration

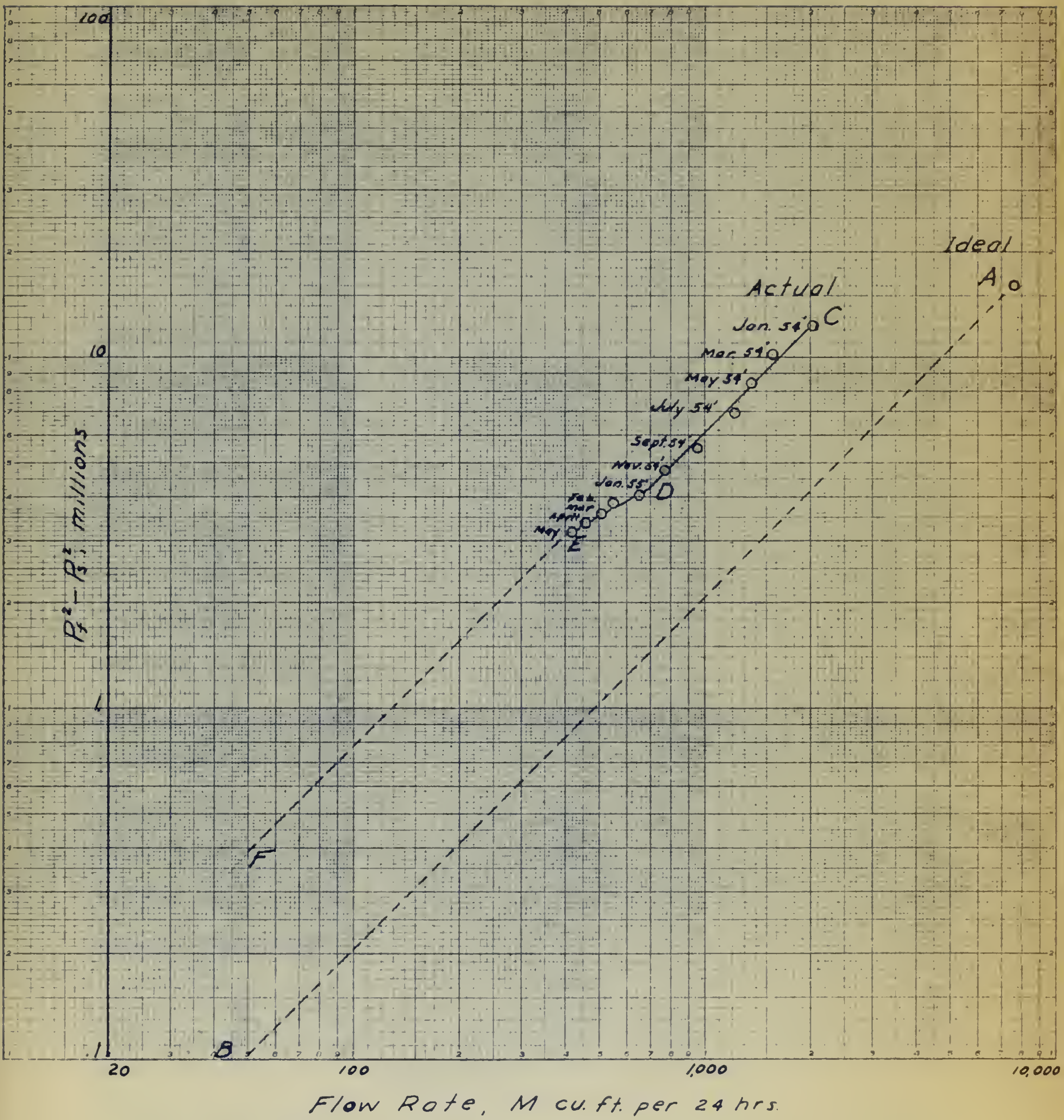

Figure 6. Average Well Flow Rate Decline

of the adverse effects of production practices as is brought out in Section V, B and C. Using this n value of one, the coefficient (C) for the 30 wells came to .456. These values of C and n were justified by an average value of C equal to .45 for 127 wells on which the recorded data appeared to be the most accurate. The value of C for each individual well in this case was obtained by dividing the flow rate (Q) by $(P_f^2-P_s^2)$, $P_f$ being the closed-in individual well-head pressure plus the pressure caused by the weight of the gas column, and $P_s$ again neglected.

Readers might be interested in the calculation of average permeability as shown in Appendix II where the value of C equal to .456 was substituted in the Darcy's law radial flow equation for viscous flow. Though a rough assumption had to be made for the drainage radius and though the flow may not be considered as radial in all cases, the computed permeability of 4.05 millidarcies as compared to the estimated permeability of ten millidarcies tends to substantiate the assumption that the value of C is not excessive. Two samples blown from wells in the Leidy gas field averaged 10.9 millidarcies.[21]

In consideration of the above, the curve AB in Figure 6 may be considered to represent the production rate that could have been expected from the average well with decreasing values of $(P_f^2-P_s^2)$ had the physical characteristics of the well and the producing formation remained constant, and had the wells been so spaced as to have the average formation pressure acting on each well.

## B. Effect of Well Spacing and Production Practices on Production Rate

As pointed out in the previous section, curve AB (Figure 6) represents the declining production rates with declining ($P_f^2-P_s^2$) values that could have been expected from average, undamaged, properly spaced wells. Curve CD (Figure 6) represents the actual average production rate per well with declining average reservoir pressures as shown in Figure 4. Points on curve CD were determined by dividing the total monthly production rates (Appendix III) by the average number of producing wells as of the date indicated (Appendix IV) and plotting these rates per well against the ($P_f^2-P_s^2$), $P_f$ being considered as the formation pressure shown by Figure 4 and $P_s$ being estimated as 600 pounds per square inch. The deficiency in production rate per well for any value of ($P_f^2-P_s^2$) is represented by the horizontal distance between the two curves. This loss can be attributed to local pressure depletions in densely drilled areas and to physical damage to wells brought on by the rapid production rate.

Losses in production rate resulting from dense well spacing and consequent local pressure depletions can be well illustrated by considering areas F, G, and H in Figure 2, where on May 31, 1954 some 73 wells were producing under a formation pressure of about 1700 pounds per square inch. If the back pressure at the sand face was 600 pounds per square inch, the production rate per well expressed as a per cent of the production rate which would have been attained under the average reservoir pressure of 2895 pounds per square inch at that time was

$$\frac{(1700^2-600^2)(100)}{(2895^2-600^2)} = 31.5 \text{ per cent}$$

Actually the formation pressure acting on many of the wells was probably considerably less than the average for the area. It is therefore obvious

that a well drilled in this area at that time produced gas at less than one-third the rate that could have been expected of it had unit operation been in effect, or that the same total production rate for this area could have been achieved with less than one-third of the wells.

Production losses caused by water coning, well caving, etc. cannot be well illustrated from the data available, although it would be a simple procedure to shut in wells occasionally and to plot the Q versus the $(P_f^2-P_s^2)$ on logarithmic paper. A line through successive points thus obtained would indicate whether or not a well is being damaged. A curve that bent toward the pressure axis would be indicative of water coning or other factors hindering deliverability. If only two points are available, and a line through the two points has a slope greater than one (more than 45 degrees to the pressure axis), it will, in the author's opinion, be a positive indication of well damage. This procedure was attempted for the few state wells on which records could be found showing shut-in pressures sometime after their original gaging. However, curves thus obtained only served to prove the inadequacy and inaccuracy of recorded data. One curve showed a reverse slope, indicating lower flow rate with increasing formation pressure.

The Bureau of Mines back-pressure method for analyzing the deliverability of gas wells, as described briefly in Section V, A is a much more thorough and detailed procedure than that described above. Far greater benefits than that discussed above may also be derived from their method, although it requires the restricting of a well's flow for considerably more time than production practices in Pennsylvania permit.

## C. Estimated Losses in Ultimate Recovery

Although it is impossible to predict the ultimate gas recovery from this reservoir with any degree of accuracy, it is fairly obvious in view of the declining production rate that an uneconomical production rate will be reached long before 289 billion cubic feet of gas have been produced.

Curve DE, Figure 6, shows a recent increasing rate of decline in production rate. This may be due to a variety of factors, such as

1. Water fingering cutting off relatively high pressure gas zones.
2. Water coning near the well bore, reducing the effective sand thickness.
3. Water condensation, reducing the effective permeability to the gas.
4. Well caving
5. Structural conditions within the reservoir.
6. The temporary shutting in of an increasing number of wells (since the rate is based on the number of producing wells as drilled rather than the actual number in operation).
7. Almost total pressure depletion in densely drilled areas.

It is the author's opinion, however, that conditions in the reservoir may soon stabilize and that the flow rate after that time will continue in a directly proportional relationship with $(P_f^2-P_s^2)$; at least this is the best that can be expected. This is illustrated by the curve EF, Figure 6. Though there is little chance that this curve will hold true to the abandonment date, it is not unreasonable to expect that it will hold approximately true for the next few years. This curve may be used in conjunction with the reservoir pressure curve (Figure 4) to

provide a trial and error means for predicting future production and production rates. The dotted portions of the curves (Figure 3) were derived in this manner, considering a gradually decreasing value of $P_s$ to zero in the year 1959. By the end of the year 1959 there should have been about 240 billion cubic feet of gas produced from this reservoir.

In consideration of curves AB and EF (Figure 6) and assuming a minimum economic flow rate (Q) of 50 MCF per day at zero back pressure ($P_s$), the reservoir could be expected to be abandoned at an average pressure ($P_f$) of 632 pounds per square inch, whereas in the "ideal" case the abandonment pressure would be 316 pounds per square inch. This, according to Figure 4, reflects a loss of about 22 billion cubic feet of gas due to inefficient production practices.

Actually, it is anyone's guess as to just how far into the future this reservoir will produce gas at an economic rate. Most likely there will be numerous wells capable of producing gas at an economic rate for many years to come. It is highly probable, however, that water fingering and coning has or will cut off relatively high pressure zones within the reservoir, and that a reduced effective permeability to gas caused by water coning and condensation will seriously curtail production and reduce the ultimate recovery. An estimated loss of approximately 20 billion cubic feet of gas is considered to be conservative.

## VI. EVALUATION OF RESULTS

### A. Operational Aspects

Although this study has developed no absolute proof that there will be substantial losses in ultimate recovery of gas from this reservoir, it does indicate that such losses are very likely and presents definite proof that a great amount of manpower and materials have been unnecessarily expended. Curves AB and CD (Figure 6) show that actual production per well was only about 35 per cent of what might have been expected from the properly-spaced average well, or that about one-third of the wells, if properly spaced and undamaged, should have given the same production rate. As was pointed out in Section V, A, 2, this figure is based on a conservative estimate of the slope of the logarithmic curve AB (Figure 6) equal to one. It is possible that this curve could have had a slope of less than one, showing an increasingly wide separation between the "ideal" and "actual" curves with decreasing pressures, and therefore an increasingly poorer comparison of the actual well production rate with that of the ideal.

The ideal number of wells can only be determined by an economic balance of a great many factors, such as recoverable gas in place, drilling costs, back pressure required to prevent damaging the well or the producing formation, market demands and commitments and others. The back pressure required can be determined accurately by the Bureau of Mines method, but even this is subject to economic considerations. It may, for example, be more economical to permit minor damage to the well than to hold the back pressure sufficiently high to prevent damage entirely. Some states force the application of back pressure by restricting gas

production to 25 per cent of open flow capacity. However, this restriction is also intended to prevent gas production in excess of market demands, and there is no reason known to the author why Pennsylvania should restrict production to this rate if it can be shown that significant damage will not occur to wells producing at higher capacities. All of the above factors can best be weighed and applied through a unit operation plan, assisted perhaps by a well-spacing regulation.

It is probable that no more than two billion cubic feet per month would have been the ideal production rate from the Driftwood-Benezette field. Gas companies taking gas from this field must contract for vast quantities of gas from the Southwest to meet commitments during the winter months. Furthermore, the nature of pipeline operations as well as economic factors in the producing Southwest demand the establishment of long-term contracts with little or no seasonal variations in gas deliveries. This requires the delivery of large quantities of gas to this area during the summer months which must be stored in underground reservoirs. It is therefore obvious that the most economical rate to extract gas from this field would be a long-term rate necessary to augment deliveries from the Southwest with a minimum of storing required.

According to curve AB (Figure 6), two billion cubic feet per month could have been produced early in the productive life of the field ($P_f$ = 4600) with 27 wells producing at 25 per cent of open-flow capacity, and with 100 wells at this capacity five years later when the 120 billion cubic feet produced would have caused the reservoir pressure to drop to about 2400 pounds per square inch (Figure 4). At 50 per cent open-flow capacity, only half of these wells would be required, and 100 wells would produce two billion cubic feet or more per month until 175 billion cubic

feet of gas had been produced. Assuming that the flow rate could reach a maximum at the lower pressures without causing significant damage to the wells or the formation, 100 wells would sustain the 2 billion cubic feet per month rate for almost nine years or until 210 billion cubic feet of gas had been produced. Does not this appear more efficient and logical than has been the actual practice of drilling 277 producing wells, with more to come, to obtain the flow rate shown in Figure 3?

The above comparison of actual practices with those which might have been employed under unit operations or under well spacing regulations does not show a comparison of ultimate recovery losses. It was illustrated in Section V, C that there should be at least 20 billion cubic feet of gas lost because of inefficient production practices. Though structural conditions in the reservoir might not permit such high ultimate recovery in either the actual or the ideal case, it is probable that unit operations or adequate well spacing regulations would provide for more efficient exploration and thereby for a production rate closely approaching that shown by the curve AB (Figure 6).

## B. Economic Aspects

### 1. General

The economic aspects of production practices may be illustrated roughly as follows:

(a) Before this reservoir is abandoned there will probably have been 300 producing wells drilled -- 200 more than is conservatively estimated to be the ideal as stated in the previous section. At $75,000 per well, this will amount to an unnecessary expenditure of $15,000,000.

(b) It is estimated that at least 60 billion cubic feet of gas will have been stored and re-extracted beyond that which would have been necessary at the two billion per month rate. At an estimated cost of five cents per thousand cubic feet for storing and re-extracting, this will amount to $3,000,000.

(c) Twenty billion cubic feet of gas estimated to be lost due to open flow production practices, at an estimated net value of about ten cents per M cubic feet[22] will amount to a loss of $2,000,000.

(d) It is estimated that about 75 billion cubic feet of gas would have increased in value by at least two cents per M cubic feet had it been possible to produce this gas on a seasonal contract or at a slower rate. This will amount to $1,500,000.

(e) There have been numerous relatively minor excessive expenditures, such as expenses for operating compressor stations, additional well maintenance costs due to open flow production practices, excess gathering lines, etc.

In view of the foregoing illustration, it is reasonable to assume that $20,000,000 have or will be wasted by the production practices employed in the Driftwood-Benezette gas reservoir. Furthermore, a large

portion of these losses will be paid by the consumer in the form of high gas prices or in taxes to make up for the losses from state-owned tracts.

2. Private Landowners

Much of the land overlying this reservoir is privately owned small tracts of one acre or less. Such a landowner's fair share of the gas, considering 40,000 acres total and 280 billion cubic feet of gas as recoverable, is 7,000 M cubic feet. At one-eighth royalty this figure is further reduced to roughly 900 M cubic feet, which would amount to $247.50 at the current price of 27½ cents per M cubic feet. It is conservatively estimated that many small tract landowners have or will receive at least a hundred times this figure. Their excess profits obviously resulted in losses from less densely drilled areas, which in this field are mostly state-owned tracts.

## VII. CONCLUSIONS AND RECOMMENDATIONS

It is concluded that there have been about 200 excess wells drilled in the Driftwood-Benezette field; that there could not possibly have been a fair and equitable distribution of the gas among the various landowners; that very probably there have or will be large quantities of gas left in the reservoir because of open-flow production practices; that sound engineering principles are not observed in gaging wells and in evaluating their performance, and that all of these are directly attributable to the lack of petroleum regulatory statutes in Pennsylvania. It is further concluded that the general public supports a large share of the inequities, gas losses and excess expenses either in higher gas prices or in decreased revenue from publicly owned land.

The obvious recommendation, therefore, is that the citizens of Pennsylvania demand the enactment of state statutes which will prevent this waste of manpower, materials, and petroleum resources, and which will insure the protection of correlative rights of landowners.

The details of the varied petroleum conservation measures and unitization statutes are beyond the scope of this paper. The average citizen, however, should not be so much concerned with these details as by the fact that nothing is being done to remedy the current inefficient and unfair production practices. Citizens should place their faith in an Oil and Gas Commission appointed for the purpose of recommending appropriate conservation and unitization statutes and for enforcing the statutes after they are enacted. No person need fear monopolistic practices or the deprivation of his property without the due process of law. He is protected from these under federal law.

It is additionally recommended that the State immediately institute a program to acquire, compile and correlate information needed for accurate engineering studies, and to make this information readily available to all interested parties. No information relating to well production should be confidential. The very least that should be done is the enactment of a law requiring that all gas wells be shut in for a minimum of 48 hours once a year and that shut-in pressures be recorded and reported to an appropriate state regulatory body. Open-flow capacities, or flow rates against stated back pressures, should be recorded at the time wells are shut in, and likewise reported. Though this information will not suffice for accurate computation of the wells' performance by the Bureau of Mines back-pressure method, it will provide for considerably more accurate engineering studies than are currently possible. This recommendation would be superfluous if adequate petroleum conservation laws were enacted, for effective conservation presupposes a requirement for accurate knowledge of both the gas reservoir and the producing wells, which can only be gained from extensive and accurate data.

# APPENDICES

## APPENDIX I

## Producing Wells in the Driftwood-Benezette Gas Field

| Well No. and Area* | Name and Number | Drilling Completed | Depth | Flow Mcf/day | Initial W.H.P. psig |
|---|---|---|---|---|---|
| 1-A | S.C. Eaton, Jr. #1(Sylv.) | 9-15-51 | 5922 | 4,000 | 3925 |
| 11-N | Bearpaw Rod & Gun #1 (Fralich) | 5-5-52 | 5876 | 4,900 | 3950 |
| 23-O | B & O #1 (Plymouth) | 6-23-52 | 5952 | 80 | - |
| 25-A | Caldwell #1 | 7-9-52 | 5836 | 1,000 | 3500 |
| 29-A | Mix Run School Lot #1 | 7-25-52 | 5830 | 3,300 | 3950 |
| 36-N | J. W. Moate #1 | 8-18-52 | 6143 | 6,880 | 850 |
| 37-A | B. R. & G. #1 (Fox) | 8-29-52 | 5802 | 3,200 | 2850 |
| 38-A | Caldwell #1 | 9-10-52 | 5846 | 700 | - |
| 41-A | Caldwell #2 | 10-3-52 | 5857 | 3,400 | 2700 |
| 43-O | McMillian Est. #1(Delta) | 10-10-52 | 5820 | 6,100 | 3400 |
| 45-O | S. C. Eaton #6 | 10-13-52 | 5996 | 3,500 | 3340 |
| 47-A | St. 2 Tr. 19 | 10-27-52 | 7051 | 1,000 | 3650 |
| 50-A | Moate #1 (Fox) | 11-14-52 | 5862 | 1,200 | 3050 |
| 52-O | S. C. Eaton, Jr. #4 | 11-26-52 | 5903 | 838 | 2700 |
| 53-A | S. C. Eaton, Jr. #2(Sylv) | 12-8-52 | 6227 | 1,620 | 2500 |
| 54-N | St. 1 Tr. 20 | 12-8-52 | 5927 | 4,500 | 3655 |
| 55-O | S. C. Eaton, Jr. #2(NYSM) | 12-9-52 | 5944 | 2,100 | 2250 |
| 57-S | Charleroi Mt. Club #1 | 12-30-52 | 6975 | 2,800 | 3810 |
| 58-N | St. 2 Tr. 20 | 12-31-52 | 6408 | 1,900 | 3200 |
| 59-A | S. Moate #1 (Pamco) | 1-2-53 | 5840 | 2,560 | 1775 |
| 60-A | S. Moate #2 | 1-2-53 | 5851 | 2,166 | 2925 |
| 61-O | Eaton #7 | 1-3-53 | 5822 | 2,274 | 2170 |
| 62-A | Brookbank #1 | 1-5-53 | 5887 | 3,100 | 3250 |
| 63-N | H. A. Moate #1(Sylvania) | 1-10-53 | 6072 | 177 | 660 |
| 64-B | H. L. Pearsall #1 | 2-2-53 | 5975 | 3,000 | 3400 |
| 65-A | H. A. Moate #2 | 2-18-53 | 5984 | 134 | 1520 |
| 66-W | Clyde L. Smith #1 | 2-20-53 | 6075 | 239 | - |
| 67-O | S. C. Eaton #5 | 2-20-53 | 5980 | 2,386 | 1805 |
| 69-F | Wm. Wadring #1 | 3-9-53 | 6153 | 713 | 800 |
| 72-F | W. A. Thurby #1 | 3-24-53 | 6101 | 8,000 | 4000 |
| 74-Q | Sagamore Hunt Club #1 | 4-1-53 | 6893 | 18,200 | 2150 |
| 75-S | Catherine Bartoletta #1 | 4-11-53 | 6134 | 9,500 | 3950 |
| 77-N | Eaton #8 | 4-21-53 | 6390 | 3,450 | 1740 |
| 79-S | Charleroi Mt. Club #3 | 5-2-53 | 6936 | 17,000 | - |
| 80-N | Clyde Smith #2 | 5-14-53 | 6150 | 1,017 | 1310 |
| 81-N | Eaton #9 | 5-15-53 | 6810 | 2,600 | 1745 |
| 82-B | B & O #2 | 5-27-53 | 5870 | 1,200 | 1900 |
| 84-S | Charleroi Mt. Club #2 | 6-1-53 | 6943 | 5,250 | 3300 |
| 85-R | Sagamore Hunt Club #1 | 6-2-53 | 6903 | 8,900 | 3675 |
| 86-S | Johnson Est. #1 | 6-3-53 | 6307 | 9,800 | 4020 |
| 88-B | St. 4 Tr. 19 | 6-10-53 | 6019 | 300 | - |
| 89-N | Moate #3 | 6-12-53 | 6592 | 1,038 | 1400 |
| 92-O | Charles Buell #1 | 6-20-53 | 6168 | 400 | 2860 |

*Wells shown by number and area in Figure 2. Missing numbers in the sequence indicate dry holes drilled in or near the field.

## APPENDIX I (Continued)

| Well No. and Area* | Name and Number | Drilling Completed | Depth | Flow Mcf/day | Initial W.H.P. psig |
|---|---|---|---|---|---|
| 93-N | H. A. Moate #5 | 6-22-53 | 6040 | 1,473 | - |
| 94-N | H. A. Moate #4 | 6-22-53 | 6190 | 2,100 | 2575 |
| 96-F | Bateman #1 | 6-27-53 | 6112 | 16,980 | 3830 |
| 97-F | B & O RR #1(Mid-Atlantic) | 7-11-53 | 6087 | 12,250 | 3600 |
| 98-A | B & O #1 (Chs. Sample) | 7-14-53 | 5880 | 4,500 | 2300 |
| 99-O | McMillian #1 (Kane) | 7-22-53 | 5994 | 1,100 | 880 |
| 101-F | Theo. Stem #1 | 7-22-53 | 6085 | 8,500 | 3720 |
| 102-F | O. Johnson #1 | 7-23-53 | 6202 | 9,250 | 3750 |
| 103-K | Pearsall #1 (Fralich) | 7-28-53 | 6974 | 25,500 | 3700 |
| 104-H | Van Voorhees #1 (Simon) | 7-29-53 | 6099 | 9,600 | 3880 |
| 105-F | J. Miller #1 | 8-1-53 | 6048 | 7,000 | 3745 |
| 106-B | Charleroi #6 | 8-7-53 | 6218 | 2,700 | 3720 |
| 107-S | St. 4 Tr. 29 | 8-10-53 | 6870 | 2,075 | 3550 |
| 108-F | B. Johnson #1 | 8-11-53 | 6196 | 5,000 | 3020 |
| 109-F | P.R.R. #1 | 8-11-53 | - | 4,200 | - |
| 110-F | B. Johnson #2 | 8-11-53 | 6119 | 4,000 | 3170 |
| 111-F | J. Miller #2 | 8-14-53 | 6122 | 5,200 | 3000 |
| 112-F | Grafton (Camp Shanty) #1 | 8-14-53 | 6146 | 5,750 | 3000 |
| 113-A | H. A. Moate #6 | 8-14-53 | 6023 | 3,000 | 2250 |
| 114-G | R. Weiss #1 | 8-16-53 | 6141 | 5,000 | 2500 |
| 115-N | Pontzer #1 | 8-18-53 | 6116 | 13,700 | 3000 |
| 116-F | Sam Ena #1 | 8-18-53 | 6110 | 9,600 | 3700 |
| 117-B | Brookbank #2 | 8-20-53 | 5896 | 2,600 | 2300 |
| 118-G | Bartolette #2 | 8-20-53 | 6269 | 10,500 | - |
| 119-F | Overturf #1 | 8-21-53 | - | 9,000 | - |
| 120-B | A. J. Moser #1 | 8-21-53 | 5995 | 2,300 | 3100 |
| 121-D | Vause #1 | 8-22-53 | 6109 | 3,125 | 3925 |
| 122-F | Nicolo Pascuzzi #1 | 8-24-53 | 6160 | 1,800 | 3200 |
| 123-F | Thunderbird Camp #1 | 8-25-53 | 6137 | 5,700 | 2860 |
| 124-H | Johnson Est. #3 | 8-25-53 | 6263 | 16,000 | 3200 |
| 125-N | Mackey #1 | 8-28-53 | 6105 | 14,500 | — |
| 126-I | Stiveson #1 | 8-31-53 | 6163 | 5,731 | 3000 |
| 127-I | W. A. Thurby #2 | 9-1-53 | 6276 | 5,300 | 2725 |
| 128-F | J. H. Roger #1 | 9-1-53 | 6272 | 5,700 | 2750 |
| 129-H | Gambel #1 | 9-3-53 | 6121 | 34,000 | 3360 |
| 130-I | Steffy #1 | 9-4-53 | 6215 | 7,000 | 3000 |
| 132-S | St. 2 Tr. 29 | 9-9-53 | 6947 | 4,332 | 3220 |
| 133-E | Johns #1 | 9-10-53 | 6073 | 8,530 | 3050 |
| 134-A | P.R.R. #2 | 9-10-53 | 5860 | 1,800 | 1000 |
| 135-SS | St. 1 Tr. 33 | 9-18-53 | 6392 | 7,350 | 3920 |
| 136-Q | Sagamore Hunt #4 | 9-22-53 | 6890 | 2,067 | - |
| 137-O | Overturf #2 | 9-25-53 | 6088 | 14,700 | 2500 |
| 138-N | H. Bleish #1 | 9-26-53 | 7011 | 7,300 | - |
| 139-G | Rothrock #2 | 9-28-53 | 6108 | 12,300 | 2590 |
| 140-G | B & O #2 (Mid-Atlantic) | 9-28-53 | 6131 | 3,000 | - |
| 141-F | Coleman #1 | 9-29-53 | 6147 | 5,300 | 1960 |
| 142-N | Rothrock #3 | 9-30-53 | 6128 | 8,600 | - |

## APPENDIX I (Continued)

| Well No. and Area* | Name and Number | Drilling Completed | Depth | Flow Mcf/day | Initial W.H.P. psig |
|---|---|---|---|---|---|
| 143-T | Charleroi Mt. Club #5 | 9-30-53 | 6305 | 8,000 | 2800 |
| 144-H | Johnson Est. #2 (Kets) | 10-1-53 | 6497 | 6,800 | 2600 |
| 145-F | Hot Shot Camp #1 | 10-3-53 | 6160 | 3,470 | 1980 |
| 146-H | Van Voorhees #1 (Kahle) | 10-3-53 | 6114 | 11,000 | 2575 |
| 147-F | Mountain Camp #1 | 10-6-53 | 6190 | 3,750 | 1900 |
| 151-T | Ahlborn Coal Co. #1 | 10-12-53 | 6960 | 28,000 | - |
| 152-I | Thurby #4 | 10-13-53 | 6394 | 7,960 | 2800 |
| 154-G | Charleroi #10 | 10-14-53 | 6118 | 16,000 | 2550 |
| 155-E | Pasley Ober #1 | 10-17-53 | 6064 | 4,750 | 3600 |
| 156-AA | St. 2 Tr. 25 | 10-20-53 | 6999 | 6,000 | 3260 |
| 157-MM | St. 1 Tr. 32 | 10-21-53 | 7034 | 1,313 | 3140 |
| 158-L | St. 6 Tr. 20 | 10-21-53 | - | 3,400 | 3500 |
| 159-Z | St. 5 Tr. 29 | 10-24-53 | 6914 | 14,850 | 3290 |
| 160-A | Pearsall #1 (Sylvania) | 10-26-53 | 6975 | 6,000 | 3375 |
| 161-H | Rothrock #1 | 10-25-53 | 6099 | 7,000 | - |
| 162-P | St. 2 Tr. 27 | 10-30-53 | 6935 | 10,849 | 3440 |
| 163-D | M. Mindroburiak #1 | 10-31-53 | 6092 | 1,438 | - |
| 164-I | St. 1 Tr. 34 A | 11-2-53 | 6975 | 8,500 | 3625 |
| 165-FF | St. 9 Tr. 29 | 11-2-53 | 6900 | 14,671 | 3620 |
| 166-AA | St. 2 Tr. 30 | 11-2-53 | 6977 | 5,000 | 3460 |
| 167-G | Rothrock #5 | 11-2-53 | 6112 | 8,000 | 1850 |
| 168-F | Green #1 | 11-3-53 | 6154 | 3,300 | 1600 |
| 169-H | Charleroi R & G #7 | 11-4-53 | 6102 | 26,000 | 3250 |
| 171-F | Sam Enz #1 (Shearer) | 11-5-53 | 6310 | 5,900 | - |
| 172-E | Billings-Mason #2 | 11-10-53 | 6062 | 4,800 | - |
| 173-Q | St. 1 Tr. 27 | 11-11-53 | 6936 | 10,500 | 3210 |
| 175-Q | Sagamore Hunt Cl. #3 | 11-13-53 | 6128 | 22,500 | 3065 |
| 176-F | Cora Bennett #1 | 11-17-53 | 6185 | 1,474 | 1600 |
| 177-R | St. 1 Tr. 28 | 11-20-53 | 6938 | 20,100 | 3210 |
| 178-H | Rothrock #4 | 11-22-53 | 6119 | 11,250 | - |
| 179-R | St. 3 Tr. 29 | 11-25-53 | 6965 | 4,642 | 3210 |
| 180-H | B & R #4 (Mid-Atlantic) | 11-25-53 | 6069 | 4,900 | 1500 |
| 181-AA | St. 1 Tr. 30 | 11-25-53 | 6566 | 412 | 3000 |
| 182-J | St. 1 Tr. 26 | 11-25-53 | 6903 | 4,073 | 3225 |
| 183-F | Belts #1 | 11-26-53 | 6157 | 4,200 | 1500 |
| 184-F | Mowry #1 | 11-26-53 | 6842 | 7,000 | - |
| 185-F | Lawrence Winslow #1 | 11-28-53 | 6891 | 3,373 | 2600 |
| 186-H | Pontner #2 | 12-3-53 | 6175 | 8,200 | 1450 |
| 187-X | Denver Miller #1 | 12-3-53 | 6885 | 8,200 | 3750 |
| 188-I | Allegheny Camp #1 | 12-3-53 | 6169 | 3,000 | 1450 |
| 189-J | Ahlborn Coal #1 | 12-3-53 | 6999 | 8,400 | 3150 |
| 190-F | Overturf #3 | 12-4-53 | 6240 | 1,100 | - |
| 191-R | Sagamore Hunt Cl. #2 | 12-4-53 | - | 6,500 | 3100 |
| 192-I | Thurby #5 | 12-4-53 | 6175 | 8,000 | 2100 |
| 193-H | Charleroi #9 | 12-5-53 | 6187 | 10,750 | - |
| 194-F | B & O RR #5 | 12-5-53 | 6062 | 4,200 | 2400 |
| 195-F | Lewis Jourdain #1 | 12-7-53 | 6199 | 1,350 | 1500 |
| 197-F | Arthur Davis #1 | 12-9-53 | 6212 | 2,700 | 1450 |

## APPENDIX I (Continued)

| Well No. and Area* | Name and Number | Drilled Completed | Depth | Flow Mcf/day | Initial W.H.P. psig |
|---|---|---|---|---|---|
| 198-T | St. 6 Tr. 29 | 12-10-53 | 6965 | 17,196 | 3100 |
| 199-F | Davis & Snyder #1 | 12-11-53 | 6136 | 2,560 | 1450 |
| 200-G | Ahlborn Coal #2 | 12-14-53 | 6390 | 2,300 | 2900 |
| 201-Q | St. 3 Tr. 27 | 12-23-53 | 7015 | 4,333 | 2850 |
| 202-AA | St. 3 Tr. 28 | 12-26-53 | 6964 | 1,100 | 3150 |
| 203-H | Dumble #2 | 12-27-53 | 6172 | 10,000 | 1250 |
| 205-F | Camp Kiski #1 | 1-2-54 | 6137 | 2,646 | 1340 |
| 206-W | Wm. Laughlin #1 | 1-2-54 | 6258 | 3,125 | 3750 |
| 207-E | Sam Ems #2 (Mid-Atlantic) | 1-2-54 | 6103 | 7,810 | 3100 |
| 208-E | Cooks Camp #1 | 1-4-54 | 6146 | 4,275 | 3600 |
| 209-AA | St. 8 Tr1 29 | 1-5-54 | 6940 | 342 | 3380 |
| 210-I | Stivason #1 | 1-6-54 | 6380 | 7,500 | 2590 |
| 211-T | Charleroi B & O #4 | 1-6-54 | 6380 | 7,500 | 2590 |
| 212-EE | St. 1 Tr. 31 | 1-8-54 | 7031 | 140 | - |
| 214-D | Schiller #1 | 1-13-54 | 6102 | 3,000 | - |
| 215-F | St. 1 Tr. 34 | 1-15-54 | 6383 | 2,588 | 1900 |
| 217-C | H. & J. Mason #2 | 1-15-54 | 6140 | 6,000 | 3750 |
| 216-F | King Gold Club #1 | 1-15-54 | 6116 | 2,000 | 1400 |
| 218-T | St. 7 Tr. 29 | 1-26-54 | 6893 | 9,811 | - |
| 219-P | Pearsall #2 (Sylvania) | 1-26-54 | 6223 | 24,300 | 2723 |
| 220-T | Ahlborn Coal #2 | 1-26-54 | 6935 | 4,500 | 2150 |
| 221-F | Wm. Woodring #1 (Maddox) | 1-27-54 | 6224 | 6,000 | 1600 |
| 222-F | Camp Linda #1 | 1-30-54 | 6183 | 1,650 | 1050 |
| 223-H | Charleroi #8 | 2-1-54 | 6204 | 7,300 | - |
| 225-BB | St. 5 Tr. 31 | 2-4-54 | 7007 | 4,875 | 3500 |
| 227-H | B & O #6 | 2-5-54 | 6118 | 6,100 | - |
| 228-B | B & O #2 (Chs. Sample) | 2-10-54 | 6973 | 600 | 1800 |
| 229-E | Sam Ems #3 | 2-11-54 | 6224 | 1,438 | 3150 |
| 230-T | St. 12 Tr. 29 | 2-11-54 | 6940 | 3,523 | 2800 |
| 231-G | Ahlborn Coal #2 | 2-11-54 | 6985 | 7,000 | 2125 |
| 232-AA | St. 1 Tr. 29 | 2-12-54 | 6905 | 4,760 | 2510 |
| 233-H | Thurby #6 | 2-13-54 | 6923 | 4,100 | 1450 |
| 234-I | Dollinger #1 | 2-13-54 | 6442 | 1,178 | 3580 |
| 236-H | Heffelfinger #1 | 2-15-54 | 6254 | 557 | - |
| 239-G | Wm. Shuck #1 | 2-19-54 | 6052 | 1,438 | 3000 |
| 240-M | Shingledecker #1 | 2-26-54 | 6259 | 1,300 | 3750 |
| 241-OO | St. 1 Tr. 36 | 3-1-54 | 7155 | 12,800 | 3880 |
| 243-W | St. 6 Tr. 31 | 3-4-54 | 6444 | 40,234 | 3560 |
| 245-D | Dents Run Coal #1 | 3-10-54 | 6092 | 400 | 2340 |
| 246-P | St. 5 Tr. 27 | 3-12-54 | 6159 | 82 | 1650 |
| 247-F | B & O #1 (J.I. Shearer) | 3-13-54 | 6132 | 557 | 950 |
| 248-G | Ahlborn Coal #3 | 3-16-54 | 6993 | 5,538 | 1850 |
| 249-R | St. 4 Tr. 28 | 3-16-54 | 6998 | 4,770 | 2050 |
| 252-EE | St. 1 Tr. 34B | 3-22-54 | 7295 | 125 | - |
| 254-W | St. 1 Tr. 38 | 3-25-54 | 6226 | 5,454 | 3850 |
| 255-L | St. 2 Tr. 25 | 3-30-54 | 6995 | 4,860 | 2600 |
| 256-P | St. 4 Tr.27 | 3-30-54 | 7122 | 13,000 | 1850 |
| 257-CC | St. 5 Tr. 28 | 3-31-54 | 6911 | 6,000 | 1050 |

## APPENDIX I (Continued)

| Well No. and Area | Name and Number | Drilling Completed | Depth | Flow Mcf/day | Initial W.H.P. psig |
|---|---|---|---|---|---|
| 258-MM | St. 4 Tr. 33 | 4-3-54 | 6201 | 4,854 | 3500 |
| 259-I | Thurby #7 | 4-3-54 | 6918 | 21,000 | 1450 |
| 260-Y | St. 5 Tr. 34A | 4-10-54 | 6094 | 8,500 | 2825 |
| 261-U | Bleish #3 | 4-12-54 | 6941 | 968 | 1550 |
| 262-T | Ahlborn Coal #4 | 4-12-54 | 6868 | 4,000 | - |
| 263-N | Amy Laughlin #1 | 4-13-54 | 6254 | 852 | 2700 |
| 268-X | St. 3 Tr. 31 | 4-16-54 | 6381 | 7,810 | 3260 |
| 269-R | St. 8 Tr. 26 | 4-18-54 | 6741 | 2,427 | 2000 |
| 270-Q | Sagamore #5 | 4-18-54 | 6475 | 6,400 | 1775 |
| 272-II | St. 2 Tr. 38 | 4-22-54 | 6625 | 6,000 | 3625 |
| 274-T | Ahlborn Coal #5 | 4-27-54 | 6938 | 4,000 | 1575 |
| 275-Y | St. 1 Tr. 34B | 4-25-54 | 7151 | 1,000 | 3550 |
| 276-Z | St. 2 Tr. 34A | 4-28-54 | 7000 | 308 | 1950 |
| 277-OO | St. 3 Tr. 32 | 4-29-54 | 7176 | 5,523 | 2980 |
| 280-N | Bleish #4 | 5-1-54 | 7001 | 8,500 | 1425 |
| 281-X | Parks #1 (Kahle et al) | 5-3-54 | 6428 | 3,250 | 2875 |
| 282-E | Billings and Maxon #1 | 5-3-54 | 6119 | 4,600 | 2160 |
| 284-F | Bateman #1 | 5-5-54 | 6146 | 696 | 700 |
| 285-Q | St. 7 Tr. 25 | 5-7-54 | 6060 | 2,350 | 2150 |
| 286-X | Danielson #1 | 5-8-54 | 6254 | 475 | 3000 |
| 287-W | St. 1 Tr. 25 | 5-12-54 | 6992 | 7,035 | 2450 |
| 288-MM | St. 2 Tr. 33 | 5-17-54 | 7019 | 4,151 | 3160 |
| 289-W | Logue #1 | 5-17-54 | 6247 | 1,400 | 2560 |
| 290-U | St. 13 Tr. 29 | 5-19-54 | 6892 | 4,900 | 2800 |
| 291-BB | St. 5 Tr. 30 | 5-20-54 | 7024 | 5,731 | 2560 |
| 292-X | Parks #1 (Layton) | 5-20-54 | 6393 | 2,438 | 2500 |
| 294-J | St. 6 Tr. 26 | 5-21-54 | 6929 | 3,021 | 2450 |
| 295-T | Charleroi #12 | 5-27-54 | 7039 | 4,400 | 1850 |
| 296-X | St. 10 Tr, 29 | 5-27-54 | 6944 | 550 | 2500 |
| 297-X | St. 4 Tr. 34A | 5-29-54 | 7112 | 250 | 1650 |
| 298-DD | St. 6 Tr. 6 | 6-1-54 | 7080 | 3,479 | 2940 |
| 299-MM | St. 5 Tr. 33 | 6-1-54 | 6313 | 14,210 | 2916 |
| 301-J | St. 2 Tr. 26 | 6-5-54 | 6934 | 2,085 | 2175 |
| 302-Z | St. 3 Tr. 34A | 6-7-54 | 7029 | 4,272 | 2650 |
| 304-K | St. 9 Tr. 26 | 6-9-54 | 6959 | 4,973 | 2050 |
| 305-OO | St. 1 Tr. 34C | 6-10-54 | 7106 | 1,217 | 2625 |
| 306-U | St. 14 Tr. 29 | 6-10-54 | 6809 | 38,000 | 3125 |
| 307-WW | St. 2 Tr. 32 | 6-10-54 | 7111 | 1,174 | 1790 |
| 308-KK | St. 3 Tr. 38 | 6-11-54 | 6220 | 38,000 | 3125 |
| 309-F | Holben #1 | 6-12-54 | 6147 | 600 | - |
| 310-DD | St. 2 Tr. 34C | 6-19-54 | 7102 | 12,572 | 3300 |
| 311-K | R. L. Pearsall #4 | 6-21-54 | 6331 | 2,200 | 1820 |
| 312-MM | St. 2 Tr. 37 | 6-21-54 | 6224 | 4,450 | 2980 |
| 313-I | Thurby #3 | 6-22-54 | 6939 | 1,500 | - |
| 315-X | Parks #1 (Bailey) | 6-26-54 | 6366 | 1,600 | 2040 |
| 316-Q | Sagamore #7 | 6-28-54 | 6491 | 2,800 | 1425 |
| 319-D | St. 11 Tr. 26 | 7-2-54 | 6208 | 189 | 2100 |
| 320-I | Thurby #8 | 7-7-54 | 7046 | 700 | 1300 |

## APPENDIX I (Continued)

| Well No. and Area | Name and Number | Drilled Completed | Depth | Flow Mcf/day | Initial W.H.P. psig |
|---|---|---|---|---|---|
| 322-X | St. 12 Tr. 26 | 7-13-54 | 6918 | 2,218 | 2050 |
| 323-LL | St. 6 Tr. 33 | 7-16-54 | 6366 | 1,857 | 1620 |
| 324-KK | St. 4 Tr. 38 | 7-20-54 | 6287 | 213 | 2275 |
| 325-X | St. 16 Tr. 29 | 7-24-54 | 6373 | 920 | 2450 |
| 326-F | Pascuzzi #1 | 7-24-54 | 6063 | 2,463 | 1300 |
| 327-OO | St. 4 Tr. 36 | 7-29-54 | 7095 | 990 | 1850 |
| 328-BB | St. 4 Tr. 30 | 7-29-54 | 6920 | 2,936 | - |
| 329-T | St. 17 Tr. 29 | 7-30-54 | 7004 | 42,000 | 1910 |
| 332-E | St. 10 Tr. 26 | 8-2-54 | 6866 | 1,279 | 2350 |
| 334-FF | St. 11 Tr. 31 | 8-13-54 | 7102 | 1,000 | 2500 |
| 335-X | Herman Norre #1 | 8-14-54 | 6232 | 4,500 | 3700 |
| 337-KK | St. 1 Tr. 29 | 8-24-54 | 6473 | 6,100 | 3050 |
| 339-V | Denver Miller #3 | 9-3-54 | 6750 | 2,800 | 3150 |
| 340-X | Roosensteel #1 | 9-4-54 | 6232 | 3,300 | 3100 |
| 341-LL | St. 8 Tr. 33 | 9-14-54 | 6303 | 5,741 | 1340 |
| 342-HH | St. 3 Tr. 33 | 9-15-54 | 7007 | 996 | 1990 |
| 343-R | Sagamore #6 | 9-16-54 | 6417 | 2,542 | 1280 |
| 344-W | St. 7 Tr. 31 | 9-18-54 | 6315 | 1,081 | 1580 |
| 346-V | Dollinger #1 | 10-8-54 | 6262 | 5,080 | 2650 |
| 349-LL | St. 9 Tr. 33 | 10-11-54 | 6420 | 239 | 1410 |
| 350-B | St. 7 Tr. 20 | 10-11-54 | 6907 | 1,271 | 1450 |
| 351-Y | St. 11 Tr. 29 | 10-12-54 | 6950 | 3,373 | 1650 |
| 353-B | Billings and Mason #3 | 10-21-54 | 6830 | 2,250 | 1530 |
| 354-V | Steve Rupprecht #1 | 10-27-54 | 6902 | 4,200 | 2290 |
| 356-L | Pearsall #5 | 10-29-54 | 7021 | 1,835 | 1425 |
| 357-W | Paul Chase #1 | 11-6-54 | 6341 | 10,833 | 3600 |
| 358-V | Dollinger #2 | 11-9-54 | 6760 | 3,769 | 2310 |
| 359-W | Crufutt (Ross Hrs.) #1 | 11-13-54 | 6204 | 2,166 | 3175 |
| 362-C | H. & J. Mason #1 | 11-29-54 | 6932 | 134 | - |
| 363-KK | St. 2 Tr. 29 | 11-31-54 | 7145 | 1,246 | - |
| 364-GG | St. 2 Tr. 34 | 12-3-54 | 7113 | 680 | 1400 |
| 365-X | Claude Chase #1 (Kahle) | 12-10-54 | 6239 | 3,921 | 1507 |
| 366-V | Walter Turle #1 | 12-13-54 | 6216 | 4,047 | 1700 |
| 368-W | St. 3 Tr. 37 | 12-20-54 | 6884 | 3,425 | 3500 |
| 370-X | Boosters Club #1 | 1-17-55 | 6182 | 5,500 | 2500 |
| 371-X | Crown Control #1 | 1-17-55 | 6220 | 1,600 | 2160 |
| 372-W | St. 4 Tr. 37 | 1-19-55 | 7029 | 5,731 | 2725 |
| 373-GG | St. 11 Tr. 33 | 2-22-55 | 6283 | 4,275 | - |
| 374-II | St. 5 Tr. 38 | 2-23-55 | 6943 | 2,900 | 1800 |
| 375-II | St. 5 Tr. 37 | 2-25-55 | 7076 | 894 | 2850 |
| 376-W | Hall Chase #2 | 2-26-55 | 6598 | 3,000 | 2400 |
| 377-Z | St. 18 Tr. 29 | 3-3-55 | 7029 | 4,775 | 1120 |
| 378-DD | St. 7 Tr. 30 | 3-10-55 | 7225 | 696 | 1140 |
| 379-U | St. 20 Tr. 29 | 3-16-55 | 6508 | 4,055 | 1125 |

## APPENDIX II - CALCULATIONS[*]

### A. Determination of Reserves

1. P/Z Values for Graphical Solution (Figure 4)

Gas Analysis: methane 97.0%; ethane 2.10%; propane 0.1%; oxygen 0.1%; nitrogen 0.5; carbon dioxide 0.2%; molecular weight 16.3; critical pressure 673 psia; critical temperature 348°R.

Reservoir temperature 150°F[**]; surface temperature 60°F.

Original reservoir pressure P = 4035 psia as measured at the surface plus the pressure caused by the weight of the gas column in the well $P_x$. $P_x$ was calculated as follows:

$$P_w = \frac{144\ ZRT\ P_x}{MH} - .5\ P_x$$

where $P_w$ = 4035 psia well head pressure

Z = .9 (from compressibility chart for natural gas, using a pseudo reduced pressure $P_r$ of 4035 ÷ 673 = 6.0, and a pseudo reduced temperature $T_r$ of 565° R ÷ 348 = 1.622)

R = 10.71 (gas constant)

T = 565°R (average temperature in the well)

H = 6500 feet (average depth)

M = 16.3 (molecular weight)

thus

$$4035 = \frac{(144)(.9)(10.71)(565)\ P_x}{(16.3)(6500)} - .5\ P_x$$

$P_x$ = 583 pounds per square inch.

---

[*] All calculations by slide rule

[**] Estimate based on 140°F. as measured for Leidy gas field

Therefore, the original reservoir pressure $P = 4035 + 583 = 4618$ pounds per square inch absolute. The corresponding compressibility factor $Z = .97$, using $T_r = 610^\circ R$ (reservoir temperature) $\div 348 = 1.75$, and $P_r = 4618 \div 673 = 6.85$. The original $P/Z = 4618 \div .97 = 4755$.

On May 31, 1954, $P_x$ and Z were calculated as shown above. (See Figures 7 and 8)

$$\text{May 31, 1954 } P/Z = \frac{P_w + P_x}{Z} \quad \frac{2505 + 390}{.882} = 3280$$

2. Analytical Method

Original gas = gas produced + gas remaining

Considering the reservoir storage space and the reservoir temperature as remaining constant, and using the gas produced as of May 31, 1954 (Appendix III):

$$\frac{381\ P_1 V}{Z_1\ RT} = 89{,}315{,}450{,}000 + \frac{381\ P_2 V}{Z_2\ RT}$$

where 381 = standard cubic feet per mole

$P_1 = 4618$ psia (original reservoir pressure)

$P_2 = 2895$ psia (May 31, 1954 reservoir pressure)

$V$ = reservoir storage space in cubic feet

$Z_1 = .97$ (compressibility factor at original reservoir pressure)

$Z_2 = .882$ (compressibility factor at May 31, 1954 reservoir pressure)

$R = 10.71$ (gas constant)

$T = 610^\circ R$ (reservoir temperature)

$$V = \frac{89{,}315{,}450{,}000\ RT}{381(P_1/Z_1 - P_2/Z_2)}$$

$$V = \frac{(89{,}315{,}450{,}000)(10.71)(610)}{381\ (4755 - 3280)} = 1.04 \times 10^9 \text{ cubic feet}$$

$$\text{Original gas} = \frac{381\ P_1 V}{Z_1\ RT} = \frac{(381)(4618)(1.04 \times 10^9)}{(.97)(10.71)(610)}$$

$$= 289 \text{ billion standard cubic feet}$$

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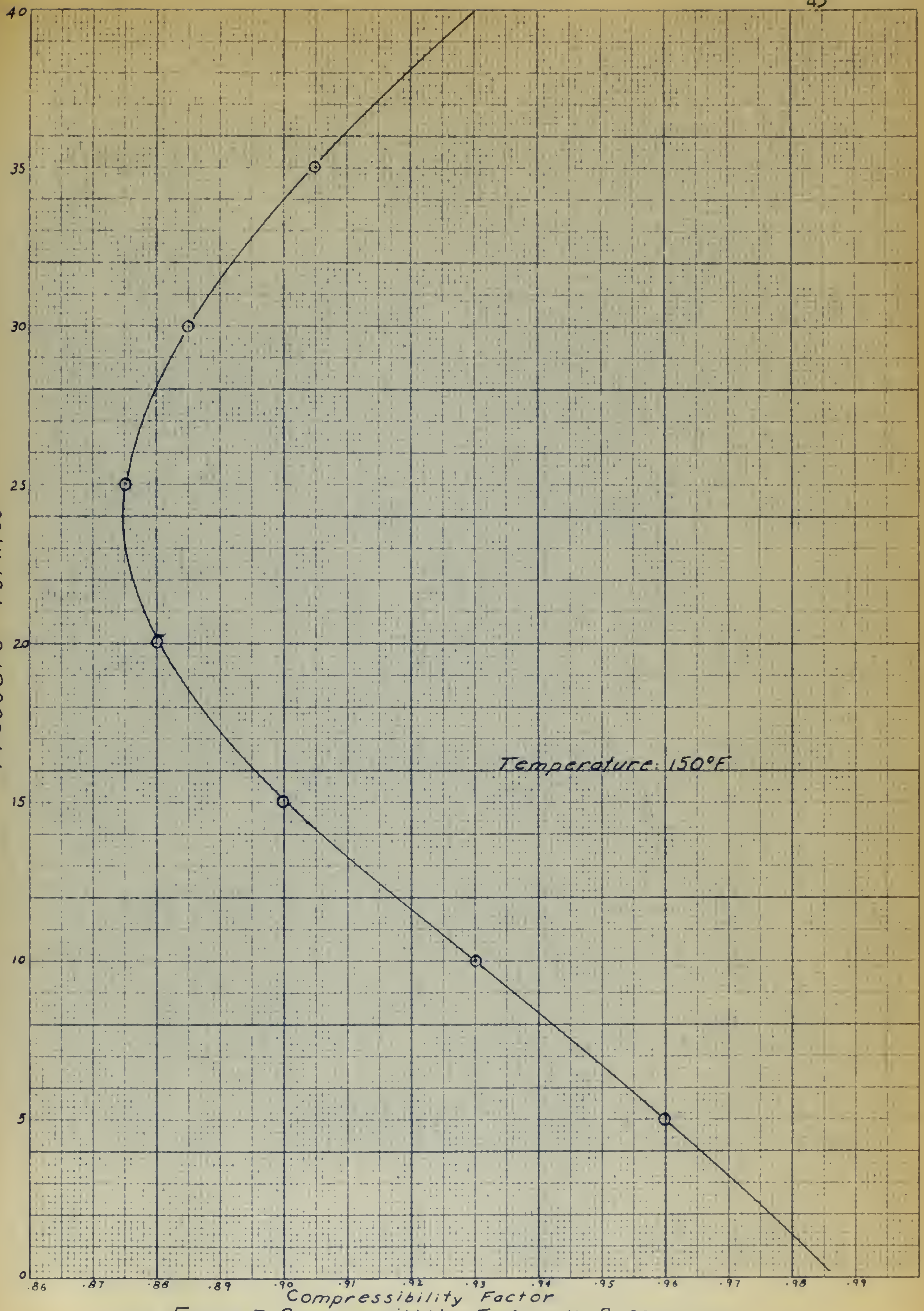

Figure 7. Compressibility Factor vs. Pressure

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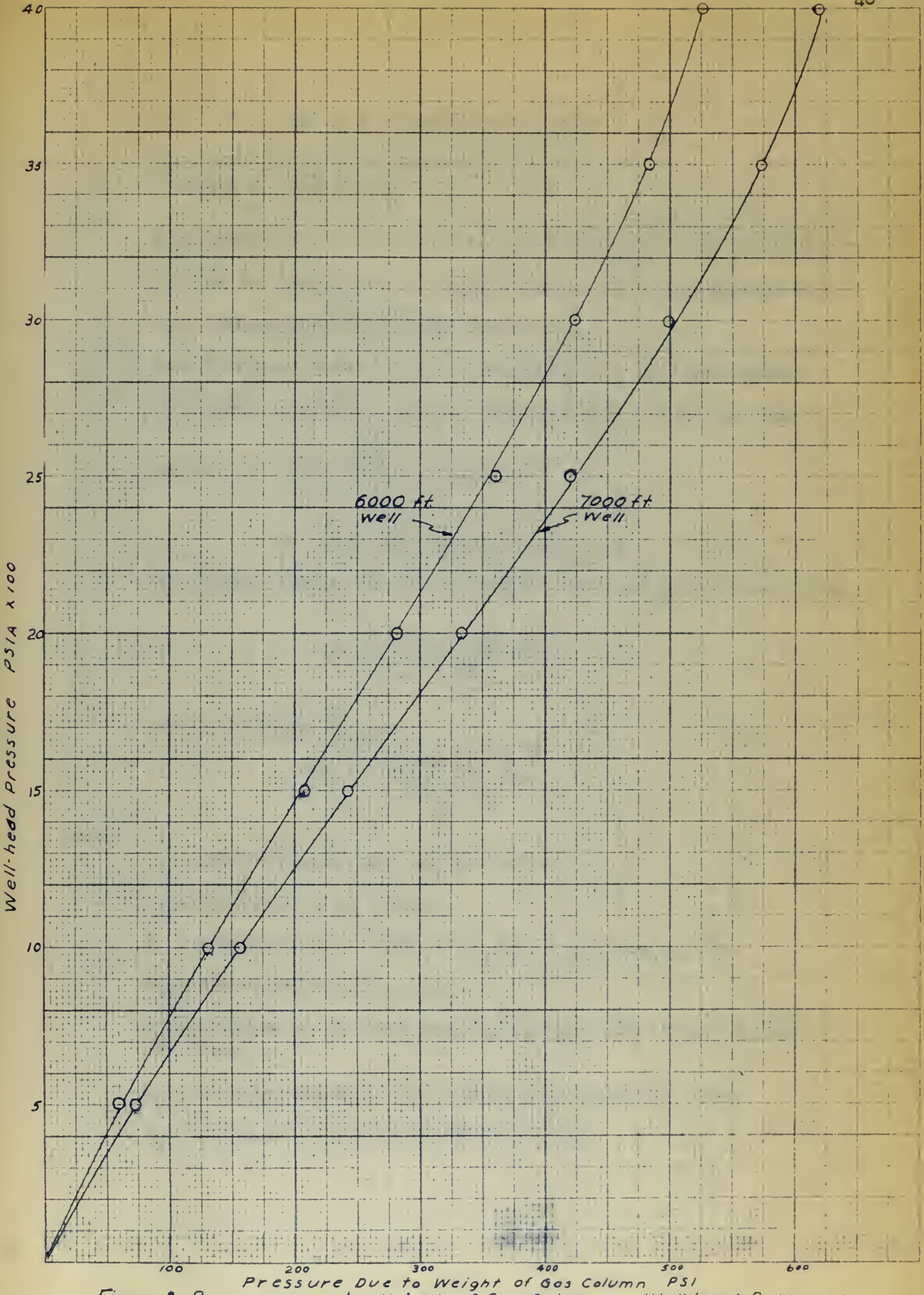

Figure 8. Pressure Due to Weight of Gas Column vs Well-head Pressure

### B. Determination of Porosity

$$\text{Porosity} = \frac{\text{pore volume}}{\text{bulk volume}}$$

Pore volume = $1.04 \times 10^9$ cu. ft. (as shown in Appendix II, Section A, 2 on the preceding page) plus an estimated 20 per cent of the pore volume for connate water saturation.

Bulk volume = approximately 42,000 acres x 17 feet averagesand thickness x 43,560 cu. ft. per acre-foot = $31.1 \times 10^9$ cu. ft.

$$\text{Porosity} = \frac{(1.04 \times 10^9)(100)}{(31.1 \times 10^9)(1-.20)} = 4.18\%$$

### C. Determination of Permeability

The Darcy's Law radial flow equation[23] for viscous isothermal flow

$$Q_b = \frac{19.88\ Kh\ (P_e^2 - P_w^2)}{P_b\ \mu\ \ln \frac{r_e}{r_w}}$$

can be rewritten to give

$$Q_s = \frac{703\ Kh\ (P_f^2 - P_s^2)}{\mu\ \ln \frac{r_e}{r_w}\ T_f}$$

where

$Q_s$ = standard cubic feet per 24 hours

$K$ = permeability in darcies

$h$ = effective sand thickness in feet (approximately 17)

$P_f$ = reservoir pressure, psia

$P_s$ = pressure at the sand face (or flowing bottom hole pressure) psia

$r_e$ = drainage radius of the well in feet (estimated 1000)

$r_w$ = radius of the well bore in feet (.256)

$\mu$ = viscosity in centipoises (about .021)

$T_f$ = flowing temperature, °R (610)

In the equation $Q = C(P_f^{\,2} - P_s^{\,2})^n$, when n equals one, C is equivalent to:

$$\frac{703\ Kh}{\mu \ln r_e/r_w \quad T_f}$$

Therefore,

$$K = \frac{C\ \mu \ln r_e/r_w \quad T_f}{703\ h}$$

substituting:

$$K = \frac{(.456)(.021)(8.27)(610)}{(703)(17)}$$

$$K = .00405 \text{ darcy or } 4.05 \text{ millidarcies}$$

## APPENDIX III

### Monthly and Cumulative Production
### (Thousands of Standard Cubic Feet)

| Date | Monthly | Cumulative |
|---|---|---|
| July, 1952 | 188,059 | 188,059 |
| August | 335,508 | 523,567 |
| September | 487,600 | 1,011,167 |
| October | 626,391 | 1,634,558 |
| November | 646,559 | 2,284,117 |
| December | 779,402 | 3,063,519 |
| January, 1953 | 707,450 | 3,770,969 |
| February | 675,666 | 4,446,635 |
| March | 702,671 | 5,149,306 |
| April | 699,867 | 5,849,173 |
| May | 914,232 | 6,763,405 |
| June | 2,064,370 | 8,827,775 |
| July | 3,325,838 | 12,153,613 |
| August | 3,813,343 | 15,966,956 |
| September | 4,631,769 | 20,598,725 |
| October | 5,921,232 | 26,519,557 |
| November | 8,547,966 | 35,067,923 |
| December | 9,417,934 | 44,085,857 |
| January, 1954 | 9,566,001 | 54,051,858 |
| February | 8,455,139 | 62,523,997 |
| March | 8,814,765 | 71,338,762 |
| April | 9,079,005 | 80,417,767 |
| May | 8,897,687 | 89,315,454 |
| June | 8,632,640 | 97,948,094 |
| July | 9,035,862 | 106,983,956 |
| August | 8,402,474 | 115,386,430 |
| September | 7,224,472 | 122,610,902 |
| October | 6,493,945 | 129,104,847 |
| November | 6,122,523 | 135,227,370 |
| December | 5,605,069 | 140,832,439 |
| January, 1955 | 5,392,746 | 146,225,185 |
| February | 4,238,335 | 150,463,520 |
| March | 4,306,508 | 154,770,028 |
| April | 3,835,448 | 158,605,476 |
| May | 3,591,968 | 162,197,444 |

## APPENDIX IV

### Producing Wells and Dry Holes by Dates

| Date | Total No. Prod. Wells | Total No. Dry Holes | Date | Total No. Prod. Wells | Total No. Dry Holes |
|---|---|---|---|---|---|
| Sept., 1951 | 1 | - | July, 1953 | 53 | 52 |
| October | 1 | - | August | 75 | 52 |
| November | 1 | - | September | 91 | 53 |
| December | 1 | 1 | October | 107 | 57 |
| January, 1952 | 1 | 1 | November | 127 | 59 |
| February | 1 | 4 | December | 144 | 61 |
| March | 1 | 7 | January, 1954 | 161 | 62 |
| April | 1 | 9 | February | 175 | 67 |
| May | 2 | 15 | March | 187 | 72 |
| June | 3 | 22 | April | 201 | 80 |
| July | 5 | 29 | May | 217 | 82 |
| August | 7 | 31 | June | 233 | 86 |
| September | 8 | 33 | July | 243 | 88 |
| October | 12 | 37 | August | 247 | 93 |
| November | 14 | 39 | September | 253 | 94 |
| December | 19 | 40 | October | 260 | 98 |
| January, 1953 | 24 | 40 | November | 265 | 100 |
| February | 28 | 40 | December | 269 | 101 |
| March | 30 | 44 | January, 1955 | 272 | 102 |
| April | 33 | 45 | February | 276 | 102 |
| May | 37 | 47 | March | 277 | 102 |
| June | 46 | 51 | April | 277 | 102 |
|  |  |  | May | 277 | 102 |

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